SNG

PROCESS SELECTION STUDY

SNG FROM COAL

FOR

MONTANA TRADE COMMISSION
BUTTE, MONTANA

DRAVO CONTRACT NO. CPD-7024
NOVEMBER 15, 1976

Dravo

CHEMICAL PLANTS DIVISION
ONE OLIVER PLAZA, PITTSBURGH, PA. 15222

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APPENDIX

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1.0 INTRODUCTION (Cont'd.)

clusive recommendation of a system or systems that would meet the requirements of the state. This report presents the results of the study and the recommendations made.

Twenty-one processes were reviewed, and eight of these were evaluated in detail.

The information base for this report has been published data and data obtained from the process licensors. Some of the data were received within bounds of confidentiality, while others were freely offered. Consideration of the interests of the process licensors and the specific treatments of the data indicate that these results be used discretely and for the purpose indicated.

The treatment of each process has been as uniform as practical. The results are valid for the purpose of comparisons among the processes, but caution is warranted in dealing with absolute values, in view of the limited time available for the preparation of this report.

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2.0 SUMMARY

This report presents the results of the coal gasification process selection study performed by Dravo Corporation for the Montana Trade Commission.

At the conclusion of the report, suitable coal gasification processes that meet the requirements of the state of Montana, are recommended.

Montana is considering coal gasification for the manufacture of synthetic natural gas (SNG) because of the anticipated curtailment of Canadian imports. In 1975, of the 75 billion cubic feet of total demand, 42 billion cubic feet were imported from Canada. By 1989, the Canadian imports will be reduced to nil, and the demand must be supplied from other sources.

2.1 Preliminary Screening

In this study, 21 coal gasification processes were considered. These included both first and second generation processes. The processes were subjected to a preliminary screening to assess their suitability with respect to Montana lignite coal and the schedule requirements of the state of Montana. Thirteen processes were eliminated on the basis of the schedule requirements alone, many of these processes

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2.0 SUMMARY (Cont'd.)

2.1 Preliminary Screening (Cont'd.)

being in early stages of development. The surviving eight processes passed the Montana lignite criterion and were therefore selected for a detailed comparative evaluation. They are:

1. Babcock & Wilcox
2. CO_2 Acceptor
3. COGAS
4. HYGAS
5. Koppers - Totzek
6. Texaco
7. Winkler
8. Lurgi

2.2 Final Evaluation

For the evaluation, all the processes were designed to produce 150 million standard cubic feet per day of SNG (925 Btu/SCF, HHV, dry) and ammonia synthesis gas equivalent to 1000 tons per day of ammonia. Dravo Corporation was provided this capacity as the basis for this evaluation. The SNG would have a moisture content of a maximum of 7 pounds per million standard cubic feet, and it would be delivered into the pipeline at 1000 psig. The plants were designed on a grass roots basis, and the site assumed was the Glasgow Air Force Base. The feed coal was assumed to be Montana lignite with the following

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2.0 SUMMARY (Cont'd.)

2.2 Final Evaluation (Cont'd.)

specifications:

Type:	Circle West Lignite, "R" bed
Mine Location:	40 miles, S/SE of Glasgow Air Force Base
Size, as received:	2" x 0", washed
Percent moisture:	35.02%, as received
Ash:	6.86%, as received
Heating Value:	6,894 Btu/lb., as received
	10,610 Btu/lb., dry

As part of the evaluation, material and energy balances were prepared for the processes, and the overall thermal efficiencies were established. Engineering, procurement and construction schedules of the plants were also prepared. The processes then were qualitatively evaluated for suitability to Montana lignite coal, degree of development, technical risk, mechanical reliability, operability and start-up, flexibility and turn-down, gasifier scale-up requirements and environmental considerations. To assess the economic viability of the processes, capital investments and operating costs were also estimated. Using the utility financing method, the product gas costs were calculated for all processes. The following economic parameters were used:

- Debt: Equity Ratio = 75:25
- Interest on Debt = 9%

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2.0 SUMMARY (Cont'd.)

2.2 Final Evaluation (Cont'd.)

- Return on Equity = 15%
- Federal Income Tax = 48%
- 20-year life, straight-line depreciation

Estimates were made of the start-up costs, working capital, manpower requirements, supplies and overhead costs.

2.3 Assignment of Point Ratings

In order to compare the processes on a quantitative basis, the processes were rated for several criteria. The technical evaluation ratings were compiled first. Then, for the overall evaluation, point ratings were also assigned for thermal efficiency and economic, financial and environmental criteria. The total point ratings were then consolidated for each process.

The technical criteria and their relative importance were selected by Dravo Corporation. The other criteria and their relative importance were selected by the Montana Trade Commission.

2.4 Conclusions

The results of the evaluation are summarized in the attached table.

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2.0 SUMMARY (Cont'd.)

2.4 Conclusions (Cont'd.)

The technical evaluation ratings show that Lurgi, Koppers - Totzek and Winkler have the higher ratings. This is as expected because they are commercially proven processes. However, in the overall evaluation, the relative merits of the HYGAS and CO_2 Acceptor processes become apparent mainly because of their high overall thermal efficiency and low gas cost. On this same basis, Koppers - Totzek and Winkler have a lower rating. Lurgi, however, maintains its high position. Thus, the three processes that are outstanding in the overall evaluation are:

PROCESS	OVERALL EVALUATION RATING
(1) Lurgi	65
(2) HYGAS	64
(3) CO_2 Acceptor	60

2.5 Recommendation

The overall evaluation ratings for the three candidate processes are so close that it is difficult to make a definitive selection of a single process. Accordingly, to compare the viability of the processes, factors such as commercial maturity must be emphasized. The Lurgi process has been demonstrated on a commercial scale, and the HYGAS and CO_2 Acceptor processes have been demonstrated on a pilot scale.

Therefore, the Lurgi process is recommended because it is a commercially demonstrated, low-risk process with a high overall thermal efficiency and low gas cost.

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2.0 SUMMARY (Cont'd.)

2.5 Recommendation (Cont'd.)

As an alternate selection, HYGAS, a second generation process, is recommended because of its high overall thermal efficiency and low gas cost.

The CO_2 Acceptor process is recommended as an alternate second generation process if conditions beyond those considered in this report would require an alternate selection.

2.6 Support Work

The following organizations contributed to this study:

- Avco Corporation prepared a report covering the energy requirements of Montana, the coal availability in Montana and a study of federal support programs for financial assistance.

- American Lurgi Corporation prepared a study for the applicability of Lurgi gasifiers, with the same basis of feed coal and capacity used in this report.

- The Lummus Company utilized the American Lurgi data to prepare a technical and economic definition of a grass roots plant.

2.0 SUMMARY (Cont'd.)

2.6 Support Work (Cont'd.)

- Morrison - Maierle, Inc., prepared an environmental report on the federal, state and local emission standards as applicable to Glasgow, Montana.

Information and data in these reports were used where required in preparation of the main body of this report. These reports are included in the Appendix.

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SUMMARY OF EVALUATION

	BABCOCK & WILCOX	CO_2 ACCEPTOR	COGAS	HYGAS	KOPPERS-TOTZEK	TEXACO	WINKLER	LURGI
Raw Coal, TPD	21,614	17,946	29,600	21,434	23,079	22,029	22,603	22,425 ***
Oxygen, TPD	11,622	--	--	2,229	11,736	10,318	5,266	3,590 ***
Raw Water, GPM	19,476	5,847	14,689	7,121	18,189	17,356	17,877	6,080 ***
Purchased Electric Power, KW	297,200	90,100	48,700	91,200	435,200	120,500	189,900	58,000 ***
Total Plant Investment, $MM	807.8	469.8	740.9	454.6	874.6	746.6	697.2	500.0 *
Gas Cost, $/MM BTU	5.55	3.08	4.13	2.62	5.89	4.79	4.73	3.11
Overall Thermal Efficiency, %	44.7	64.8	58.1	69.8	42.2	52.0	50.8	60.1**
Technical Evaluation Ratings (Top Rating = 75)	55	45	43	45	70	42	65	72
Overall Evaluation Ratings (Top Rating = 80)	44	60	51	64	46	48	55	65

* Value derived by deleting the NH_3 synthesis section from the Lummus Estimate.

** Value derived from Lummus Estimate by substituting for purchased power a coal equivalent of 10,000 BTU/KWH instead of heat equivalent of 3413 BTU/KWH.

*** Lurgi/Lummus Estimate

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3.0 NATURAL GAS REQUIREMENTS OF MONTANA

The demand and supply profiles of natural gas and crude oil for the state of Montana are presented in detail in the report from Avco Corporation to Dravo Corporation. (See Appendix B.) Pertinent portions of the information therein are summarized below.

The natural gas demand in the state of Montana reached a peak in 1973 at about 80 billion cubic feet per year. The energy crisis of that year, and the subsequent announcement by the Canadian government to systematically reduce the quantities of natural gas exported and at the same time increase the price, curtailed expanded use of natural gas in Montana and led many to reduce their requirements. In 1975, the demand dropped to 75 billion cubic feet per year. Additional reduction in demand is expected, but the magnitude of the reduction will depend on the reliability and cost of the supply.

The natural gas supply to the state of Montana can be divided into two categories:

a) that imported from Canada

b) that from wells in Montana and neighboring states.

In 1975, 42 billion cubic feet were imported from Canada, and the remaining 35 billion cubic feet were obtained from indigenous sources.

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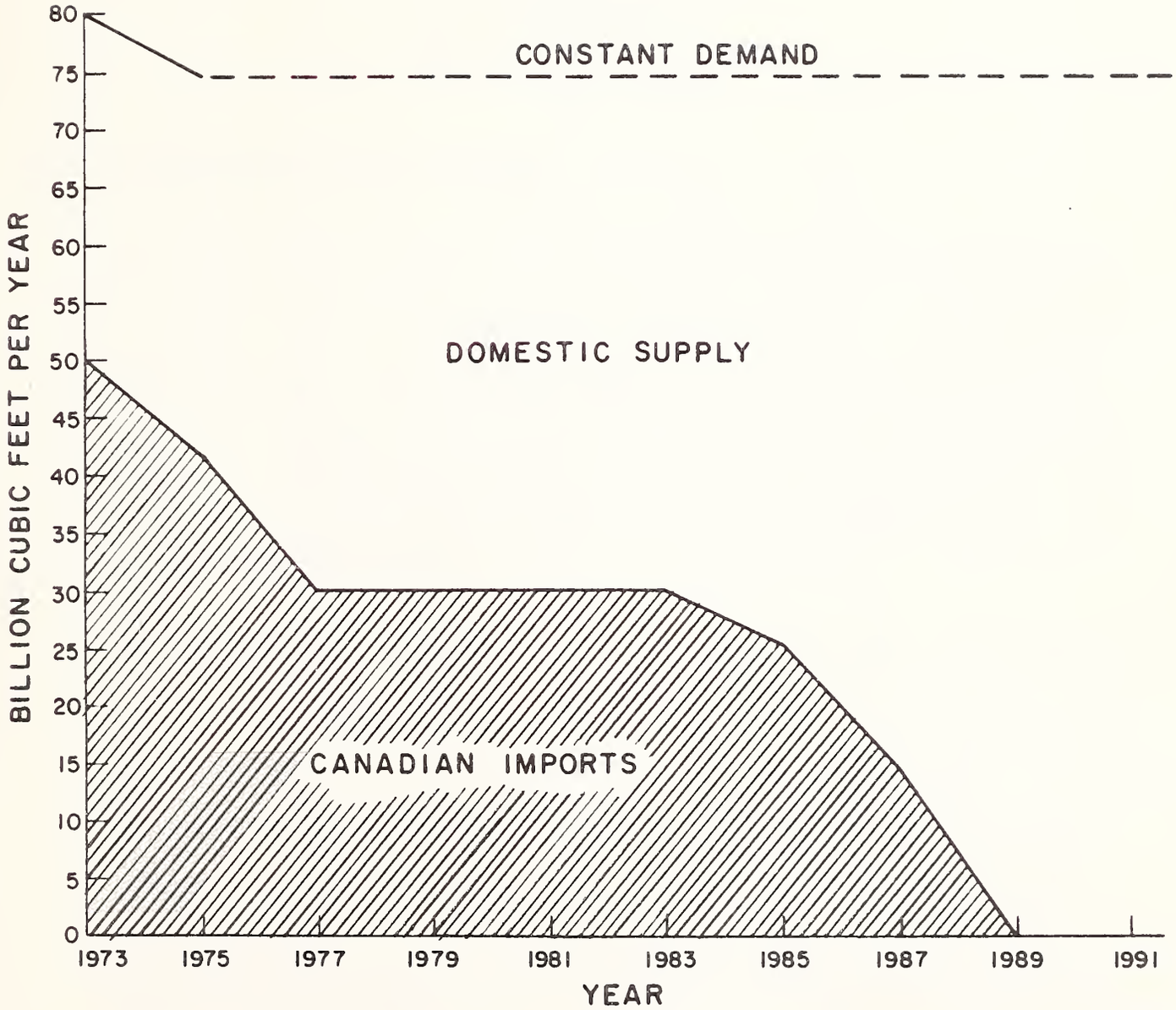
3.0 NATURAL GAS REQUIREMENTS OF MONTANA (Cont'd.)

The Canadian imports were reduced from the 1973 figure of 49 billion cubic feet and are scheduled to be reduced to 29 billion cubic feet in 1977. The imports will be reduced to zero in 1989. The attached figure shows the schedule for the Canadian imports, although the exact schedule is somewhat negotiable.

The figure also shows the demand level of the state of Montana. Assuming a constant demand, the figure indicates that a total domestic supply of 75 billion cubic feet per year (167 MM SCFD) will be required by 1989. A coal gasification plant producing 150 MM SCFD (50 billion cubic feet per year) of SNG and gas equivalent of 1000 TPD of ammonia would more than replenish the loss in Canadian imports. Dravo Corporation was given this capacity as the basis for the Process Selection Study presented in this report. A smaller plant, perhaps as small as 85 MM SCFD (28 billion cubic feet per year), would be adquate if a limited amount of conservation and a reduction in demand is assumed.



Projected Montana Supply/Demand of Pipeline Gas

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4.0 COAL AVAILABILITY IN MONTANA

Avco Corporation in their Report to Dravo Corporation presented the listings of major coal deposits in eastern Montana. (See Appendix B for the Report.) The attached table, reproduced from the Report, gives the location, quantity, and some characteristics of the coal in each bed. The map following the table shows the plant site at Glasgow Air Force Base.

The table indicates that the sub-bituminous and lignite coal deposits in eastern Montana exceed 42,000 million tons. The Glasgow Air Force Base, identified as the suitable site for the proposed plant, is within 80 miles of two large coal fields, Weldon-Timber Creek and Redwater River. The two fields alone have combined reserves of over 1300 million tons of coal. With a consumption rate of 25,000 tons per day of coal for the plant of the proposed size, the deposits in the fields will last for over 150 years if totally recoverable. Actual yields will be somewhat less.

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MONTANA BUREAU OF MINES AND GEOLOGY

Strippable subbituminous and lignite coal fields, eastern Montana

	Name of field	Coal bed	Est. reserves in millions of tons	Acreage	Average tons/acre	Ash[1]	Sulfur[1]	Btu[1]
1	Decker	Anderson-Dietz 1&2	2,239.99	25,523	87,763	4.0	.40	9,652
2	Deer Creek	Anderson-Dietz 1&2	495.65	14,214	35,397	4.0	.50	9,282
3	Roland	Roland	218.04	12,076	18,055	9.2	.74	8,164
4	Squirrel	Roland	133.41	6,208	21,490	5.5	.29	7,723
5	Kirby	Anderson	216.52	5,655	38,285	4.2	.32	8,328
		Wall	473.69	5,952	79,579			
		Dietz	834.35	17,516	47,630	5.8	.59	8,509
		Canyon	158.53	4,066	38,983	5.8	.24	8,789
6	Canyon	Wall	1,884.25	23,859	78,974	4.6	.30	9,088
		Brewster-Arnold	65.86	2,067	31,859	7.5	.40	8,444
7	Birney	Brewster-Arnold	180.55	6,969	25,905	5.1	.41	9,055
8	Poker Jim Lookout	Anderson-Dietz	872.65	19,609	44,501	5.2	.37	7,925
9	Hanging Woman Cr.	Anderson	1,583.29	30,547	51,830	4.9	.29	8,496
		Dietz	1,120.96	43,654	25,678	5.5	.33	8,078
10	West Moorhead	Anderson	883.74	19,660	44,949	5.3	.36	8,296
		Dietz	397.49	20,416	19,469	4.1	.41	7,990
		Canyon	690.19	22,547	30,611	5.6	.45	8,055
11	Poker Jim O'Dell	Knobloch	373.29	7,890	47,311	5.1	.22	8,846
		Knobloch	564.78	7,187	78,581			
12	Otter Creek	Knobloch	2,075.55	25,791	80,475	4.7	.36	8,468
13	Ashland	Knobloch	2,696.20	27,200	99,125	4.8	.15	8,421
		Sawyer A & C	357.49	20,262	17,643	4.9	.49	7,883
14	Colstrip	Rosebud	1,439.26	33,379	43,118	9.5	.12	8,836
15	Pumpkin Creek	Sawyer	2,426.50	45,695	53,102	7.5	.34	7,438
16	Foster Creek	Knobloch	708.13	27,801	25,470	7.8	.76	7,573
		Terret	460.87	27,462	16,782	5.8	.21	7,770
		Flowers-Goodale	258.90	14,444	17,924	7.8	.51	7,553
17	Broadus	Broadus	739.82	18,429	40,142	7.2	.27	7,437
18	East Moorhead	T	525.21	15,559	33,756	6.2	.57	7,120
19	Diamond Butte	Canyon	418.02	21,363	19,566	4.8	.43	7,330
20	Goodspeed Butte	Cook	628.95	13,446	46,775	10.6	1.63	6,771
21	Fire Gulch	Pawnee & Cook	336.69	8,486	39,674	3.8	.33	7,739
22	Sweeney-Snyder	Terret	326.33	10,921	29,880	9.1	.11	8,175
23	Yager Butte	Elk & Dunning	1,175.86	26,924	43,673	4.8	.33	7,646
		Cook	312.02	14,507	21,507	6.7	.63	7,254
24	Threemile Buttes	Canyon & Ferry	225.40	13,836	16,289	5.5	.94	6,867
25	Sonnette	Pawnee	320.25	8,224	38,940	9.8	.88	6,964
		Cook	362.98	10,470	34,668	8.1	1.23	6,891
26	Home Creek Butte	Canyon & Ferry	217.21	4,851	44,774			
27	Little Pumpkin Creek	Sawyer A&C, D, X, & E	215.83	8,534	25,290			
28	Sand Creek	Knobloch	267.34	5,952	44,915	6.6	.30	7,340
29	Beaver-Liscom	Flowers-Goodale & Terret	135.87	8,851	15,350	8.1	.96	8,102
		Knobloch	491.62	17,075	28,791	7.7	.50	8,027
30	Greenleaf-Miller Creek	Rosebud, Knobloch, and Sawyer	453.71	14,918	30,413	7.5	.71	8,422
31	Pine Hills	Dominy	193.87	6,022	32,191	7.2	.53	7,293
32	Knowlton	Dominy (M & L)	747.51	19,613	38,112	7.1	.41	6,710
		Dominy (U)	120.31	4,448	27,048	5.6	.38	6,615
33	Sarpy Creek	Rosebud McKay	1,500.00	42,373	35,400	6.5	.50	8,600
34	Cheyenne Meadows	Knobloch	1,200.00	13,560	88,500	4.1	.40	8,400
35	Little Wolf	Rosebud-McKay	314.00	7,411	42,370			
36	Jeans Fork		90.00	3,800	23,685			
37	Wolf Mountains		1,922.00	31,000	62,000			
38	Lame Jones	Dominy	150.00	10,593	14,160			6,020
39	Lamesteer	Harmon(?)	35.00	1,978	17,700			6,332
40	Wibaux	C	643.00	18,518	34,720	7.9	.90	6,050
41	Little Beaver	C	134.00	8,445	15,865			
42	Four Buttes	C	91.00	5,180	17,570			6,149
43	Hodges		10.00	807	12,390			
44	Griffith Creek		10.00	568	17,700			

MONTANA BUREAU OF MINES AND GEOLOGY

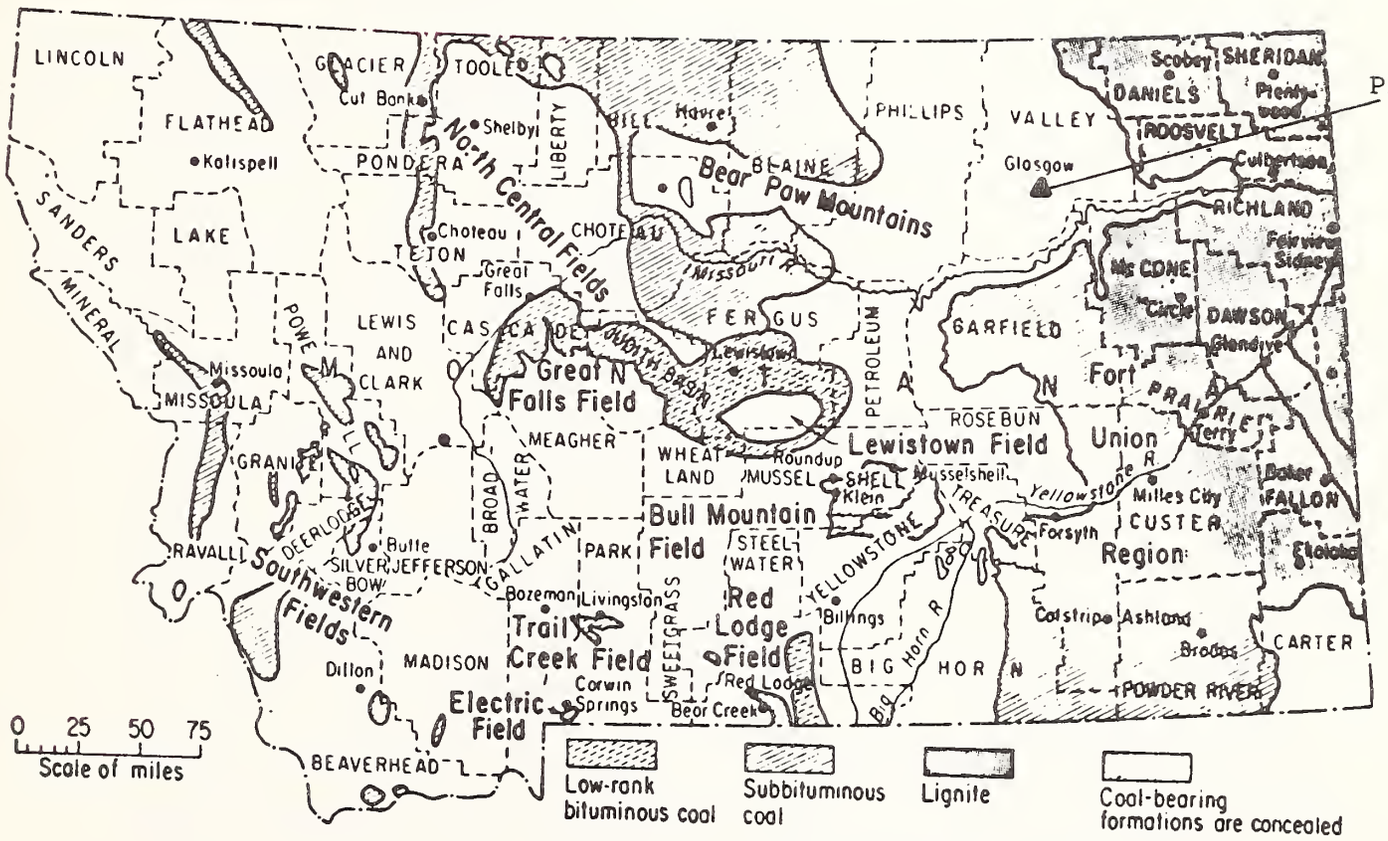
Strippable subbituminous and lignite coal fields, eastern Montana

	Name of field	Coal bed	Est. reserves in millions of tons	Acreage	Average tons/acre	Ash[1]	Sulfur[1]	Btu[1]
45	Smith-Dry Creek	G	150.00	8,475	17,700			
46	O'Brian-Alkalie Creek		150.00	8,475	17,700			
47	Breezy Flat	Pust	200.00	7,062	30,090	6.7	.50	6,660
48	Burns Creek	Pust	200.00	7,062	30,090			
49	N.F.Thirteen Mile Creek	Pust	225.00	5,085	44,250			6,880
50	Fox Lake	Pust	46.00	2,166	21,240			6,880
51	Lane	Lane	561.00	44,582	12,390			7,150
52	Carroll	Carroll	345.00	29,780	11,584	5.5	.30	7,400
53	Redwater River	S	642.00	24,181	26,550	6.1	.40	7,400
54	Weldon-Timber Creek	S	724.00	25,565	28,320			7,660
55	Fort Kipp	Ft. Kipp-Ft. Peck	331.00	14,500	22,830	4.6	.20	6,110
56	Lanark	Lanark	100.00	3,531	12,390	6.3	.40	6,853
57	Medicine Lake		58.00	3,740	15,510	7.2	1.00	6,870
58	Reserve		246.00	18,231	13,495	7.6	.40	6,599
59	Coal Ridge	Coal Ridge	150.00	19,200	17,700	7.5	.40	5,830
60	Carpenter Creek	Carpenter	50.00	3,211	14,015	6.5	.40	9,270
61	Charter	Mammoth	60.00	3,210	17,700	6.0	.90	10,190
62	Little Sheep Mtn.	A&C	200.00	10,272	19,470			
		TOTAL	42,561.93	1,152,640				

[1] "As received" basis (where more than one sample available, figures given are average figures).

By Robert F. Matson

Montana



1972 KEYSTONE COAL INDUSTRY MANUAL

Map of Montana showing Counties and Location of Coal Fields

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5.0 ENVIRONMENTAL CONSIDERATIONS

5.1 Environmental Standards

Environmental emission standards for coal conversion plants are being developed by the Environmental Protection Agency. The final engineering design of the SNG plant will have to comply with the developed standards.

In order to have a current and practical basis for environmental standards to apply in this process selection study, Morrison-Maierle, Inc., of Helena, Montana was contracted by Dravo to summarize the emission standards as applicable to Glasgow, Montana, the tentative site for the SNG plant. The summary is titled A Compendium of Federal, State, and Local Emission Standards as Applicable to Glasgow, Montana and appears in Appendix A of this report.

The Morrison-Maierle report summarizes the standards for aqueous and gaseous streams and for solid wastes. Federal, state, and local emission standards for the different contaminants of the aqueous streams are given. The state emission standards for the gaseous contaminants are given, since federal standards on these are not yet available and Valley County, Montana has adopted the state standards. For the solid wastes, the federal and state standards are given. The local standards are adopted from the state standards.

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5.0 ENVIRONMENTAL CONSIDERATIONS (Cont'd.)

5.1 Environmental Standards (Cont'd.)

It is stated in the report that federal regulations take precedence over state regulations, and state regulations over local regulations, except that the standard which affords the greatest protection to the environment is usually respected.

5.2 Environmental Control

The plant design for the eight processes evaluated in Section 7 incorporates environmental control systems such as acid gas removal systems, units to recover elemental sulfur from acid gases, stack gas scrubbing units (lime and sodium sulfite), water treatment systems (bio-treatment and lime), flares, thermal oxidizers, etc. The costs of these systems are included in the cost estimate presented in Section 7.

The plants have been designed so that the key, identifiable components in the effluents meet the environmental standards cited in Subsection 5.1. Examples of such components are: SO_2 in the gaseous streams, phenol in the aqueous streams, and ash among the solid effluents. For some of the other components, such as the suspended solids in the aqueous streams, thiophene in the gaseous streams, the quantities were not precisely determined in this study.

Final details of the environmental control systems will be developed when detailed material balances are prepared to identify the quantities of contaminants, and permit applications are filed. The systems can

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5.0 ENVIRONMENTAL CONSIDERATIONS (Cont'd.)

5.2 Environmental Control (Cont'd.)

then be designed for a minimum net intake of water and minimum contaminants in the discharge. These systems will be designed to be in compliance with the requirements of regulatory authorities.

In the plant design, all aqueous streams would be treated to be acceptable for discharge.

A discussion of the different contaminants and types of wastes and their handling follows.

5.2.1 Aqueous Streams

Coal Storage Runoff	This runoff will be sent to a holding pond for solids settling and lime addition for pH adjustment. This water can then be used as cooling water or as slag cooling water make-up. The federal regulation on the suspended coal and ash from the pond is 30-50 ppm. This regulation can be met through proper pond design.
Total Suspended Solids	The main potential sources of suspended solids are the blowdown from gas quench-scrubbers and runoff water from the slag handling system. The blowdowns will be treated in the Treatment, Disposal, and Evaporation area. Such aqueous emissions will be reduced in the TSS content to the 10 mg/l federal limit prior to their discharge. Where applicable, these

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5.0 ENVIRONMENTAL CONSIDERATIONS (Cont'd.)

5.2 Environmental Control (Cont'd.)

5.2.1 Aqueous Streams (Cont'd.)

Total Suspended Solids (Cont'd.)

blowdown waters can be recycled for slag quenching or slurry preparation.

Phenol

Phenol is produced in the Lurgi and HYGAS processes. The amount of phenol produced in the Lurgi plant (25,880 gal/day) is about five times as much as that produced in the HYGAS process. In the Lurgi process, the Phenosolvan process is used to recover the phenol and reduce its content in the effluent. The effluent from the Phenosolvan unit is processed in a bio-treatment plant. In the HYGAS process, most of the phenol leaves the plant with the oil (BTX) product. The condensates from the gas-cooling areas are expected to contain the remaining amount of phenol. The condensates are treated in the bio-treatment plant where the phenol is decomposed.

The federal limit on the level of phenols in the receiving stream has been set at 0.001 ppm, because surface waters constitute the bulk of domestic water supplies. When considering the Montana River with

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5.0 ENVIRONMENTAL CONSIDERATIONS (Cont'd.)

5.2 Environmental Control (Cont'd.)

5.2.1 Aqueous Streams (Cont'd.)

Phenol (Cont'd.)	a daily average flow rate of 610.45 MM gallons per day, the 0.001 ppm would be equivalent to 5.09 lbs/day phenol discharge.
Dissolved Solids	Water effluents from process units are lime treated to reduce the heavy metals and phosphates prior to disposal. The federal and state standards are given in Section 2.8 of the Morrison-Maierle Report.
Demineralizer Effluents	Caustic and acid used in regeneration of the demineralizer beds will be combined, neutralized, and sent to the evaporation pond.
Cooling Tower Blowdown	The blowdown will be high in dissolved solids (magnesium silicate, calcium sulfate, sulfuric acid, etc.) due to the desired quality of the recirculating cooling water. The blowdown is discharged to the evaporation pond. An organic rust inhibitor will be used to eliminate the chromate or phosphate inhibitors.

5.2.2 Gaseous Streams

Sulfur Oxides SO_x	Lime scrubbing will be used to reduce the SO_x content of the flue gases on the following processes: HYGAS,

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5.0 ENVIRONMENTAL CONSIDERATIONS (Cont'd.)

5.2 Environmental Control (Cont'd.)

5.2.2 Gaseous Streams (Cont'd.)

Sulfur Oxides SO_x (Cont'd.)

Winkler, COGAS, and Texaco. This application is on coal-fired boiler flue gases and coal-drying off gases. In the processes, the coal fines fired contain .93 wt. percent sulfur on a DAF basis. This results in about 1.3 lbs. of sulfur dioxide in the flue gas per MM Btu (HHV) of coal fines fired. For the Lurgi process, Lummus uses the Wellman Lord SO_2 recovery system. In all the four cases, only a portion of the flue gas is scrubbed so that the SO_2 content of the total flue gas can be reduced to no more than 1.2 lbs. of SO_2 per MM Btu (HHV) of coal fines fired. This maximum SO_2 emission level is specified by the Federal Environmental Protection Agency, and the same level will be used for all the processes.

In the Lurgi process, the SO_2 stream leaving the Wellman-Lord flows to a catalytic converter, where conversion of sulfur dioxide to sulfur trioxide takes place over a vanadium pentoxide catalyst. Sulfur trioxide leaving the converter is then used to manufacture concentrated sulfuric acid.

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5.0 ENVIRONMENTAL CONSIDERATIONS (Cont'd.)

5.2 Environmental Control (Cont'd.)

5.2.2 Gaseous Streams (Cont'd.)

Nitrogen Oxides NO_x

As pointed out in Section 3.3 of Morrison-Maierle Report, there are no standards established by the state pertaining directly to this parameter. Instead, the state has adopted the nitrogen oxide emission limitations as outlined in the Standards of Performance for Fossil Fuel Fired Steam Generations (39 FR 20791, June 14, 1974). Lime scrubbing on coal-fired boilers off-gas will reduce NO_2 loading. It is anticipated that this will be acceptable. Final treatment requirements will be determined during the detail design phase of the project.

Hydrogen Cyanide HCN

The exact amounts of HCN formed in different processes is not known at the present time. Only by experimental runs with the sample coal can this be determined with a reasonable accuracy. HCN is formed in quantities small enough that accurate data on the quantities cannot be predicted. However, it is formed in quantities large enough for its discharge to the atmosphere to be considered seriously.

In the HYGAS process, HCN present in the raw gasifier gas is 265 ppm (690 lb/hr), and this is the process

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5.0 ENVIRONMENTAL CONSIDERATIONS (Cont'd.)

5.2 Environmental Control (Cont'd.)

5.2.2 Gaseous Streams (Cont'd.)

Hydrogen Cyanide HCN (Cont'd.)

with the largest quantities of HCN formed. In all the processes, the raw gas is treated in an acid gas removal system: either a Benfield system or a Selexol system. Both systems are capable of removing large percentages of HCN, and the HCN would then appear in the acid gas. The acid gas is treated for sulfur recovery either in a Claus plant or in a Stretford plant. In the Claus plant, the HCN will be incinerated. In a Stretford plant, it will react irreversibly to produce NaCNS, which is removed as a liquid waste effluent. Depending upon the quantity of HCN handled, the Stretford plant may be a single column plant, or it may be a double column plant to minimize the loss of the Stretford solution along with the discharge NaCNS. Stretford licensors offer proprietary methods to treat the Stretford plant liquid discharges to make them environmentally compatible.

Carbonyl Sulfide COS

The COS in the gasifier off-gas is hydrolyzed in the Benfield acid gas removal step. The COS is thus converted to H_2S, and the H_2S is readily reduced

Dravo

5.0 ENVIRONMENTAL CONSIDERATIONS (Cont'd.)

5.2 Environmental Control (Cont'd.)

5.2.2 Gaseous Streams (Cont'd.)

Carbonyl Sulfide COS (Cont'd.)

to elemental sulfur, either in the Claus plant or in the Stretford plant.

For the processes that use the Selexol (HYGAS, COGAS, & Texaco) or Rectisol (Lurgi) physical absorption systems for acid gas removal, the COS is removed from the gasifier gas, and it appears in the acid gas fed to the Stretford unit. The Stretford unit does not remove COS. The Stretford off-gas is combusted to convert the residual (∿50ppm) H_2S to SO_2 and the COS will also be oxidized simultaneously to SO_2. The exact amount of COS is not known at this time, but it is expected to be small enough to meet the SO_2 emission standards.

Thiophene $<(CH:CH)_2>S$

At present, it has not been verified if any of the processes produce thiophene. However, if it is produced, it can be removed by activated carbon filters.

Water H_2O

Because of the hazard of fog formation, cooling towers should be located away from public roads and operating plant areas.

Dravo

5.0 ENVIRONMENTAL CONSIDERATIONS (Cont'd.)

5.2 Environmental Control (Cont'd.)

5.2.2 Gaseous Streams (Cont'd.)

Carbon Monoxide CO

The CO emission from coal-fired boiler vent gases from the COGAS, HYGAS, Winkler, and Texaco processes will be incinerated prior to discharge to atmosphere.

Hydrogen Sulfide H_2S

For the CO_2 Acceptor process which utilizes a Claus and SCOT plant combination for elemental sulfur recovery, the H_2S-bearing off-gas from the SCOT is rerouted through the Claus plant incinerator for conversion to elemental sulfur. For the processes with a Stretford plant (all other processes), the H_2S in the feed acid gas is reduced to 50 ppm. The Stretford vent gas is incinerated in a flare. The H_2S concentrations will be thus reduced to the maximum permissible concentrations which are (1) 0.03 ppm 1/2-hour average, not to be exceeded more than twice in any five consecutive days, (2) 0.05 ppm 1/2-hour average, not to be exceeded over twice a year.

Particulates

The coal storage piles are provided with wind screens and dust suppression systems utilizing water and surface-sealing compounds. Grinding and screening takes place in an enclosed area with equipment provided for dust collection. Ash is handled wet to control dusts.

Dravo

5.0 ENVIRONMENTAL CONSIDERATIONS (Cont'd.)

5.2 Environmental Control (Cont'd.)

5.2.2 Gaseous Streams (Cont'd.)

Carbonyls
$Fe(CO)_5$
$Ni(CO)_4$

Iron carbonyl $Fe(CO)_5$ and Nickel carbonyl $Ni(CO)_4$ may form when CO comes in contact with an active (reduced) iron or nickel surface at low temperatures and atmospheric pressures. These carbonyls are considered the most toxic inorganic materials known. The formation of $Fe(CO)_5$ and $Ni(CO)_4$ in CO shift and methanation units which use iron and nickel catalysts respectively can be avoided by purging and cooling with an inert gas preferably at temperatures above 300°F.

5.2.3 Solid Wastes

Ash

The ash (and slag) are disposed of by landfill. The landfill sites will be selected in compliance with the federal and state regulations stated in Section 4.0 of the Morrison-Maierle Report. If the carbon content of the ash is high (above 15-20%), it represents a fire hazard, and the ash must be covered with dirt after disposal. All processes were examined for safety of disposing of the ash produced by landfill.

Dravo

5.0 ENVIRONMENTAL CONSIDERATIONS (Cont'd.)

5.2 Environmental Control (Cont'd.)

5.2.3 Solid Wastes (Cont'd.)

Ash (Cont'd.) The COGAS and Babcock & Wilcox processes produce slag with less than 1% and 5% carbon respectively. In the Koppers-Totzek process, carbon conversion is high for lignite and the carbon in the ash is expected to be about 5%. In the CO_2 Acceptor process, the ash is disposed of with the reject dolomite. The net carbon content of the solids is a little over 1%. The Texaco process produces ash with a carbon content of about 10%. The carbon would probably be occluded in the fused ash particles. Thus, the ash from all of the above five processes may be disposed of by landfill.

The Winkler process produces char with a 45% carbon content, and it would need to be covered with soil if it were to be disposed of directly. However, in the Winkler plant design for this study, all the char is burned in the boiler, and the ash formed has a low carbon content and could be disposed of easily.

The HYGAS process generates an ash residue with a 27% carbon content. The ash will have to be

Dravo

5.0 ENVIRONMENTAL CONSIDERATIONS (Cont'd.)

5.2 Environmental Control (Cont'd.)

5.2.3 Solid Wastes (Cont'd.)

Ash (Cont'd.) covered with soil after it is disposed of by landfill.

Finally, the ash from the Lurgi process has only about 5% carbon and could be disposed of by landfill.

Sludge The sludge from water treatment and pH adjustment is to be dumped with the ash as landfill. The ash will tend to stabilize this sludge and reduce leaching.

Flake Sulfur This by-product will be stored in a building of safe, non-combustible design and transferred by enclosed equipment to minimize dust formation. It is stored dry to prevent formation of sulfuric acid.

Dravo

PROCESS SELECTION STUDY
SNG FROM COAL
FOR
MONTANA TRADE COMMISSION

6.0 PRELIMINARY SELECTIONS

With the primary objective of this project being to select a coal gasification process that best suits Montana's needs (See Sections 4 and 5), twenty-one gasification processes were considered for the proposed plant. The processes are listed in the attached table. These processes included first generation processes as well as the second generation processes. As a result of this preliminary selection screening, thirteen of the twenty-one were eliminated, and eight were selected for a detailed comparative evaluation presented in Section 7 of this report.

During this preliminary selection screening, the processes were examined for their suitability to Montana's requirements. The viable process must be able to meet the schedule requirements of Montana, and it must be operable on the Montana lignite coal. Therefore, the two criteria that were established as the basis of the preliminary selection were:

(a) Montana schedule requirements must be met; therefore, process must have been demonstrated on a commercial or semi-works pilot plant scale.

(b) Gasifier must be operable on Montana lignite or operating experience must be available on similar type of coals.

Dravo

6.0 PRELIMINARY SELECTIONS (Cont'd.)

Results of application of criterion (a) are summarized in the attached table. Thirteen processes do not satisfy the criterion. For twelve of these, neither a semi-work pilot scale plant nor a commercial plant has been built and operated, and it is anticipated that the thirteenth process (Otto Rummel) will not meet the schedule requirements. Among the twelve are BCR Low-Btu, Hydrane and U-Gas, for which only bench scale units have been built so far, and the Kellogg Molten Salt gasifier is only in a conceptual stage of development. The largest Westinghouse gasifier built so far is a 15 TPD process development unit. Similarly, the Battelle/Carbide process development unit has a 25 TPD capacity.

The Coalcon demonstration plant is in the design phase, and so is the Combustion Engineering 120 TPD pilot plant. The Foster-Wheeler 480 TPD pilot plant is under construction, with operations expected to begin in 1977. Construction of the Bi-Gas and Synthane pilot plants has been completed, but operations are yet to begin. The Otto-Rummel process was eliminated because data from a foreign based process licensor is difficult to obtain and the data would not be available expeditiously enough to satisfy the schedule requirements of this project.

The number of processes was reduced to eight. These were further tested by applying criterion (b) to them. All the eight processes satisfied

Dravo

6.0 PRELIMINARY SELECTIONS (Cont'd.)

criterion (b), i.e., they were considered operable using the Montana lignite coal. A detailed discussion of the operability on Montana lignite for each of the eight processes is presented in Section 7.0.

Thus, eight processes passed the preliminary screening, and these are evaluated in detail in Section 7.0. The processes are:

1) Babcock & Wilcox
2) CO_2 Acceptor
3) COGAS
4) HYGAS
5) Koppers - Totzek
6) Texaco
7) Winkler
8) Lurgi

PROCESS SELECTION STUDY
SNG FROM COAL
FOR
MONTANA TRADE COMMISSION

PRELIMINARY SELECTIONS: APPLICATION OF CRITERION (A)

	PROCESS	SEMI-WORKS PILOT SCALE DEMONSTRATION	COMMERCIAL DEMONSTRATION
1.	Babcock & Wilcox*	YES	NO
2.	Bi-Gas	NO	NO
3.	Combustion Engineering	NO	NO
4.	Foster-Wheeler	NO	NO
5.	Koppers-Totzek*	YES	YES
6.	Texaco*	YES	NO
7.	Battelle-Carbide	NO	NO
8.	BCR Low-BTU	NO	NO
9.	CO_2 Acceptor*	YES	NO
10.	COGAS*	YES	NO
11.	Hydrane	NO	NO
12.	HYGAS*	YES	NO
13.	Synthane	NO	NO
14.	U-Gas	NO	NO
15.	Westinghouse	NO	NO
16.	Winkler*	YES	YES
17.	Lurgi*	YES	YES
18.	AI Molten Salt	NO	NO
19.	Otto-Rummel	YES	NO
20.	Coalcon	NO	NO
21.	Kellogg Molten Salt	NO	NO

*Processes that passed Criterion (a)

Dravo

PROCESS SELECTION STUDY
SNG FROM COAL
FOR
MONTANA TRADE COMMISSION

7.0 FINAL PROCESS EVALUATION

7.1 Bases of Evaluation

The eight processes selected in Section 6 for the final evaluation were examined in detail, and their relative merits were compared. The information generated as a result of this comparison en route to final recommendation (Section 9) is presented in this Section.

Both the technical and economic aspects of the processes were compared. For each process, a grass roots plant was designed with all the auxiliary facilities included. The plant site assumed was Glasgow Air Force Base, Montana. The plant was designed to produce 150 MM SCFD of SNG (925 + Btu/SCF, HHV, dry) and a gas stream to produce sufficient ammonia synthesis gas equivalent to 1000 TPD of ammonia. The SNG would have a moisture content of a maximum of 7 pounds per MM SCF, and it would be delivered into the pipeline at 1000 psig.

The processes were designed to include all grass roots facilities. Net imports into the plants asssumed were coal, raw water, electric power, and catalysts and chemicals. Specification of the Montana Lignite coal appears in the attached table. Water was used for all cooling duties. Air coolers will be used wherever possible in the final design.

Dravo

PROCESS SELECTION STUDY
SNG FROM COAL
FOR
MONTANA TRADE COMMISSION

FEED LIGNITE COAL SPECIFICATION

Type: Circle West Lignite, "R" Bed

Mine Location: 40 miles, S/SE of Glasgow Air Force Base

Size, as received: 2" x 0", washed

Proximate Analysis:

Moisture	35.02 wt%, as received
Volatile Matter	26.45
Fixed Carbon	31.67
Ash	6.86

Ultimate Analysis:

Carbon	71.68 wt%, dry, ash free
Hydrogen	4.59
Nitrogen	1.03
Oxygen	21.75
Combustible Sulfur	0.93
Chlorine	0.02

Heating Value = 10,610 Btu/lb, dry
= 6,894 Btu/lb, as received

Ash Fluid Temperature

Reducing	2350°F
Oxidizing	2390°F

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.1 Bases of Evaluation (Cont'd.)

Steam generated was used either for process or for driving steam turbines. It is assumed that the ash and sludge would be picked up at the battery limits to transfer to landfill. The plant was designed to meet the effluent qualities spelled out in Section 5, Environmental Considerations.

Except for the gasification areas, the material and energy balance data used for the plants were from in-house information. Also, except the gasification areas, the downstream gas processing areas of the plants were designed with two parallel processing trains. The material and energy balance data used around the gasification area were those recommended by the process licensors for Babcock & Wilcox, CO_2 Acceptor, COGAS, HYGAS, Texaco, and Winkler processes. For the Koppers-Totzek process, the data were based on in-house information and published data. For the Lurgi process, a study (Appendix C) was prepared by the American Lurgi Corporation for the Montana Trade Commission, and this study was used as the basis by the Lummus Company to prepare the technical and economic definition of the plant (Appendix D). The Lummus data were used in this report with adjustments made for consistency of comparison bases. The ammonia synthesis section was deleted from the Lummus estimate to derive the total plant investment. Also, thermal efficiency values used in this report were based on the coal equivalent of 10,000 BTU/KWH for purchased power instead of the

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.1 Bases of Evaluation (Cont'd.)

heat equivalent of 3413 BTU/KWH used in the Lummus report, and the Lummus thermal efficiency was adjusted accordingly.

Besides the by-products, all process produce 150 MM SCFD of SNG and a hydrogen rich gas to produce 1000 TPD equivalent synthesis gas. It was assumed that the hydrogen rich gas would be processed outside the battery limits. The gas, after proper preprocessing to remove carbon dioxide and water, would be processed in a liquid nitrogen column to separate a stream containing hydrogen and nitrogen, which is the ammonia synthesis gas. Other components of the hydrogen rich stream, such as carbon monoxide, methane, etc., are recycled to the plant and either utilized as a fuel or fed to the methanation area along with the main stream. These recycle streams appear as inputs in the overall energy balance of the plant. Other routes to producing the ammonia synthesis gas are available and are discussed in Section 8, Alternate Products and By-Products.

The different areas in the plants of the various processes were designed to maintain a consistency of the bases, so that a fair comparison is achieved. This report does not address itself to trade-off studies, and these were not performed for any of the processes. Therefore, unless a scheme was specifically recommended by the gasification process licensor, those schemes were selected as judged to give the process in question an advantage, without actually performing the

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.1 Bases of Evaluation (Cont'd.)

trade-off studies. The key bases and selections of schemes are discussed below.

7.1.1 Coal Unloading and Handling

For the Coal Unloading and Handling area, coal was assumed to be delivered by railroad cars. A 30-day storage was assumed.

7.1.2 Acid Gas Removal

For the Acid Gas Removal (H_2S and CO_2) and the CO_2 Removal areas, the Benfield hot carbonate system was selected for all processes except HYGAS, Texaco, COGAS and Lurgi. The Benfield hot carbonate system allows processing of the feed gas at a high temperature, thus increasing the thermal efficiency. For HYGAS and Texaco, the Selexol system was selected because it has an overall advantage over the Benfield system at the high pressure levels. For COGAS, the Selexol system was selected because the process licensor recommends it, and because data were readily available with that system incorporated into the plant. Similarly, for Lurgi, the Rectisol process is selected because it is recommended by the process licensor.

7.1.3 Sulfur Recovery

For recovery of sulfur from the acid gas separated in the Acid Gas Removal system, the Stretford system was selected in all processes but the CO_2 Acceptor. The Stretford system can recover sulfur from acid

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.1 Bases of Evaluation (Cont'd.)

gas streams with very small inlet concentration of H_2S. The Claus reactors tend to be excessively large and use of pure oxygen is necessary if the H_2S concentration is below 10-15%. In all processes, except CO_2 Acceptor, the concentration is very low. In the CO_2 Acceptor process, it is high (over 20%) due to the use of the Chance process coupled with gasification, and the Claus-SCOT combination was selected for the sulfur recovery.

7.1.4 CO Shift

For the shift conversion, the conventional iron-chromium catalyst is selected for all processes except HYGAS, Texaco, and Lurgi. Both HYGAS and Texaco use water-slurry feed of coal into the gasifier, and the gasifier outlet gas has a high percentage of steam in it. To utilize this steam directly for the shift, the high sulfur cobalt-molybdenum catalyst was selected for these processes. For Lurgi the cobalt-molybdenum catalyst was also used because the original American Lurgi design incorporates it and it offers a thermal efficiency advantage. It does, however, have a less commercial experience than the iron-chromium catalyst.

7.1.5 Methanation

Methanation in all processes is the conventional fixed bed methanation with cold gas recycle, using the nickel catalyst.

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.1 Bases of Evaluation (Cont'd.)

7.1.6 Oxygen Plants

Oxygen plants, where required, are cryogenic air separation units producing oxygen with a 99.5% purity.

7.1.7 Dehydration

In all processes, prior to delivery of the product gas into the pipeline, the gas is dried in a glycol dehydration system to below 7 pounds of water per MM SCF.

7.1.8 SO_2 Removal

In all processes except Lurgi, the flue gases from the coal burning boilers and from other coal burning equipment are treated in a lime scrubber before they are vented to the atmosphere. The Lummus design for the Lurgi process incorporates the Wellman Lord system. This process yields concentrated SO_2 as one of the outputs, and sulfuric acid is one of the by-products in the Lurgi plant.

7.1.9 Water Supply and Waste Treatment

Raw water is pumped from the Missouri River, 80 miles away from the plant site. To ensure a continuous raw water supply, a raw water reservoir with a 7-day storage capacity is provided in all plants. Condensates that are likely to contain organic contaminants are treated in the bio-treatment plant, the

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.1 Bases of Evaluation (Cont'd.)

aeration basins for which are designed for a 45-hour retention time. The cooling tower blowdown is discharged to the evaporation pond.

In Subsection 7.2, the generated data are presented, followed by the qualitative technical evaluation of each process. Subsection 7.3 summarizes the technical evaluation data. Subsection 7.4 covers the economic bases and data. Subsection 7.5 presents the procedure and summary of the overall evaluation leading to final recommendation.

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation

In this subsection, the description, technical evaluation, process block flow diagram and project schedule of each of the eight selected processes is presented. The eight processes are:

1) Babcock & Wilcox
2) CO_2 Acceptor
3) COGAS
4) HYGAS
5) Koppers - Totzek
6) Texaco
7) Winkler
8) Lurgi

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.1 Babcock & Wilcox

PROCESS DESCRIPTION

The Babcock & Wilcox (B&W) entrained flow gasifier, operating at 175 psig, is constructed with an outer pressure shell and an inner tube wall covered with castable refractory in the reaction zone. Pulverized lignite and oxygen are injected through two rows of horizontal burners located in the lower section of the gasifier. The product gas exits through the top, and slag exits from the bottom of the unit. Heat is recovered from the product gas by generating low pressure steam in the waterwall tubes. Four gasifiers, 8 ft. I.D. and 158 ft. high, are needed to produce the 150 MM SCFD of SNG and the gas required for 1000 TPD of ammonia production.

The lignite feed is partially dried as it is being pulverized to 70 percent through 200 mesh. An external dryer lowers the moisture content of the coal to 7.5 percent. The prepared feed is then pneumatically transported to a lock hopper system for injection into the gasifier.

The combustion reaction between the lignite and oxygen takes place in the lower section of the reaction zone at approximately 3400°F.

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.1 Babcock & Wilcox (Cont'd.)

Temperature control is accomplished by spraying water in through the burners. Ash, in the form of molten slag, is continuously withdrawn from the bottom of the gasifier into a slag quench tank. Circulating water cools the slag, producing a sand-like material, and transports it to an ash pond for disposal. The settled ash in the pond is disposed of in a landfill.

Steam generation in the waterwall and the water gas reaction cools the gas to 1800°F before leaving the gasifier. Any char exiting with the gas is collected in a pair of cyclones and returned to the gasifier. The gas is further cooled to 450°F in a waste heat boiler by generating 1500 psig steam. This steam is superheated in an external heater fired with fuel gas recycled from the nitrogen wash column. The gas is then quenched to 100°F in a dehumidification tower and compressed to 555 psig.

The compressed gas enters a Benfield acid gas removal system where essentially all of the H_2S and CO_2 are removed. This separated acid gas is then fed to a Stretford plant where elemental sulfur is recovered as a by-product.

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.1 Babcock & Wilcox (Cont'd.)

The purified gas stream exits the acid gas absorber at 240°F and is heated by the CO shift product gas. It then enters a zinc oxide guard catalyst bed where trace amounts of sulfur compounds remaining in the gas are removed. The gas stream is split, 18% of the gas passing through CO shift while the remainder bypasses it. The amount of CO shifted is that required to yield a 3.1:1 hydrogen to carbon monoxide ratio in the mixture when these two streams are recombined after the shift. A sidestream is taken off as the feed to the ammonia synthesis plant and the remaining gas is fed to methanation at 500 psig and 300°F.

In the cold gas recycle methanation unit, 99.9 percent of the carbon monoxide in the feed gas is converted to methane. This raw SNG is passed through another Benfield system where the CO_2 formed in CO shift is removed. The CO_2 is vented to the atmosphere. The purified SNG is dehydrated in a glycol dehydration unit and compressed to 1000 psig. Surge bottles are provided on the product gas line to smooth out minor process upsets.

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.1 Babcock & Wilcox (Cont'd.)

TECHNICAL EVALUATION

Montana Lignite

The B&W unit was operated on a commercial basis for almost two years with West Virginia coals. It also operated with lignite mined in the Lake DeSmet area of Wyoming. This lignite contained over 25% moisture in the as received condition and was found to gasify easily over the ratio of oxygen to lignite ratios tested. As a slagging gasifier, the B&W unit requires ash fusion temperatures below about 2600°F. This is possible with many coals, including the lignite chosen for this study.

Degree of Development and Technical Risk

The B&W gasifier has been demonstrated in a semi-commercial unit and pilot scale units. The semi-commercial unit, built in 1955, had a capacity of 400 TPD of coal and was operated at near atmospheric pressure. A pilot unit built at Morgantown, W.Va. has been run at pressures up to 300 psig and capacities up to 12 TPD. Pilot work is currently underway at B&W's Alliance pilot plant. The B&W gasifier is supported by the technology developed in water wall boilers, pulverized coal feeding under pressure to blast furnaces and cyclone furnaces, all of which are commercially

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.1 Babcock & Wilcox (Cont'd.)

established. The recycle of hot char recovered from the produced gas to the combustion zone of the gasifier needs further demonstration. A large scale pressure operation would be desirable, but is not deemed necessary in view of the extensive background in individual operations.

Operability and Start-Up

As a pulverized coal unit, the gasifier can be automated with the same control and safety features as a boiler. Flashbacks in the burners are controlled by maintaining a high carrier gas velocity. The possibility of an interruption of oxygen flow will require safety shutdown and restart procedures to prevent oxygen from entering into a non-reacting volume of coal. This is similar to the operations of pulverized coal boilers.

Gasifier Scale-Up

Four gasification trains are needed to produce the required amount of product. This represents a scale-up factor of nine, based on the gasifier feed rate of the Belle, West Virginia unit and is within safe scale-up limits.

Carbon Conversion

Carbon conversion is 99.1%.

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.1 Babcock & Wilcox (Cont'd.)

Overall Thermal Efficiency

Overall thermal efficiency is 44.7%.

Mechanical Reliability

As the gasifier and feed systems have no moving parts, except the shut-off valves, a high degree of reliability is expected. The refractory in the combustion zone will, in time, wash out but is replaced by frozen slag. This is amply demonstrated by cyclone boiler technology. One such unit has achieved in excess of 95% availability.

The water walls in the upper gasifier zone cool the gas to about 1800°F and solidify ash before it reaches the cyclones. The recycle of overhead solids is similar to fly ash recycle in some boilers, but requires additional demonstration in the context of a 175 psig gasifier.

By-Products

Sulfur is recovered from acid gases in the Stretford plant at a minimum 99% purity. Ammonia formation has been expected, but has not been apparent in operations to date.

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.1 Babcock & Wilcox (Cont'd.)

Environmental Consideration

The plant is designed for compliance with established emission regulations. No special problems are foreseen for off-site disposal.

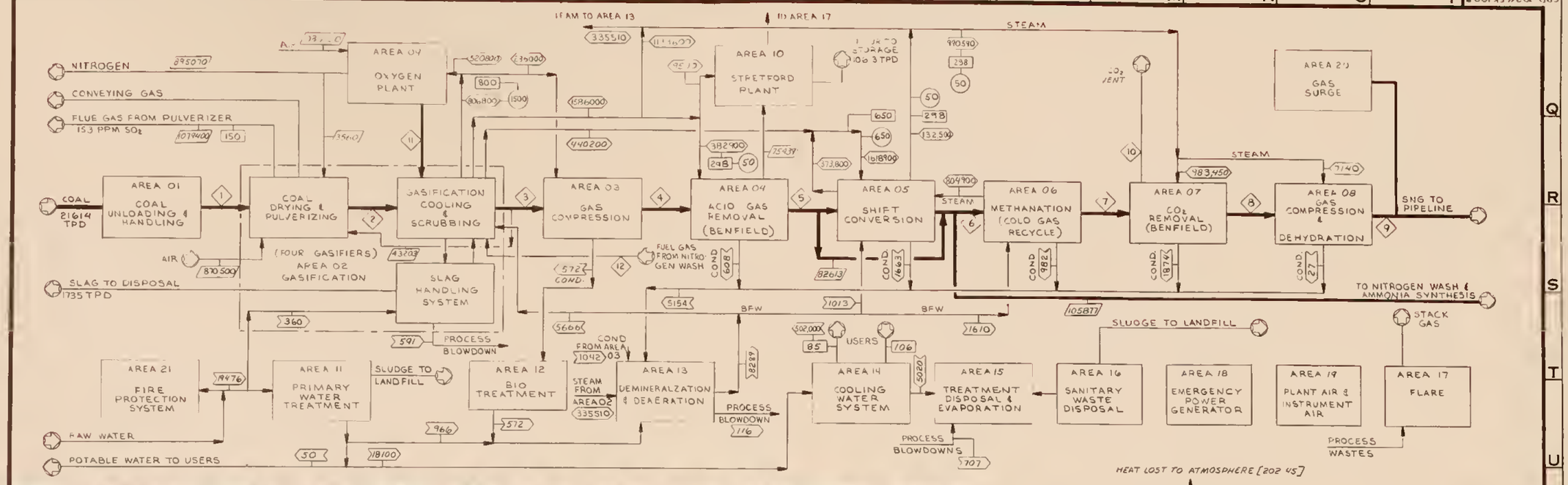
Licenses and Guarantees

Babcock & Wilcox offers process guarantees on the steam, oxygen and coal consumption of the gasifier, and quantity and quality of gas output. All royalties are on paid up bases.

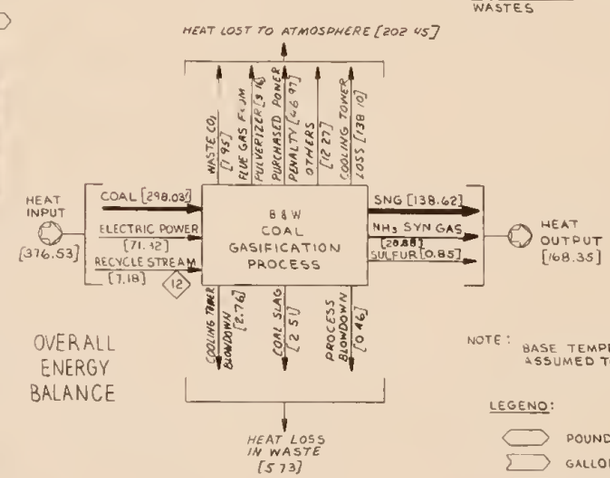
Flexibility and Turndown

The B&W gasifier is an entrained flow gasifier and accepts all types of coal.

The gasifier can be turned down to about 25% of its nominal capacity. Turndown is limited by the ability to maintain slagging temperatures in the gasifier, generation of sufficient steam for operation, and by gas quality as determined by the proportions of oxygen and steam required to maintain slagging conditions. Since there are four gasifiers for the Montana application, a turndown below the 25% capacity is possible by shutting down some of the gasifiers completely.



MATERIAL \ STREAM No.	1	2	3	4	5	6	7	8	9	10	11	12
COMPOSITION	WT %	WT %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %
MAF COAL	58.12	82.70										
ASH	6.86	9.76										
MOISTURE	35.02	7.54										
CO			60.02	60.02	66.33	14.25	0.03	0.08	0.08			78.75
CO_2			11.83	11.83	0.01	27.03	59.81	0.46	0.47	88.72		
CH_4							34.04	87.89	89.78			
H_2			24.93	24.93	27.54	44.16	1.67	4.30	4.39			2.07
H_2S + COS			0.35	0.35	2 ppm	TRACE	TRACE	TRACE				
N_2 + Ar			1.28	1.28	1.41	0.88	2.00	5.15	5.27		0.50	19.18
O_2											99.50	
H_2O			1.59	1.59	4.71	13.68	2.45	2.12	0.01	11.28		
HHV, BTU/SCF (DRY)			281.1	281.1	318.1	219.4	359.1	924.2	924.2			260.3
TOTAL LB MOLES / HR			79615	79615	72057	98956	43506	16842	16494	29218	30266	3033
TEMPERATURE °F	80	100	100	230	240	300	200	190	100	130	100	100
PRESSURE PSIG		225	175	555	540	500	480	460	1000	5	75	5
MM SCFD			724.8	724.2	655.4	900.1	395.7	153.1	150.0	266.1	295.3	27.6
TPD	21614	15189.7										11622



OVERALL ENERGY BALANCE

NOTE: BASE TEMPERATURE ASSUMED TO BE 60°F

LEGEND:

- POUNDS PER HOUR
- GALLONS PER MINUTE
- STANDARD CUBIC FEET PER MINUTE
- DEGREES FAHRENHEIT
- PSIG
- [ ] BILLION BTU'S PER DAY

$$\% \text{ OA THERMAL EFFICIENCY} = \frac{\text{HEAT OUTPUT}}{\text{HEAT INPUT}} \times 100 = \frac{168.35}{376.53} \times 100 = 44.71\%$$

DESIGNED	K.M.	7-29-76
DRAWN	M.E. PAT	8-9-76
CHECKED	KGN	10-19-76
APPROVED		
APPROVED		
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PROCESS BLOCK FLOW DIAGRAM
B&W COAL GASIFICATION

FOR MONTANA TRADE COMMISSION

Dravo CORPORATION
Chemical Plants Division · Pittsburgh, Pennsylvania

SCALE —/—/— DRAWING NUMBER CPD 7024 - SK-100B REV.

REV. DESCRIPTION DRAWN CHKD DATE REV. DESCRIPTION DRAWN CHKD DATE NO REV. RELEASED FOR APP DATE

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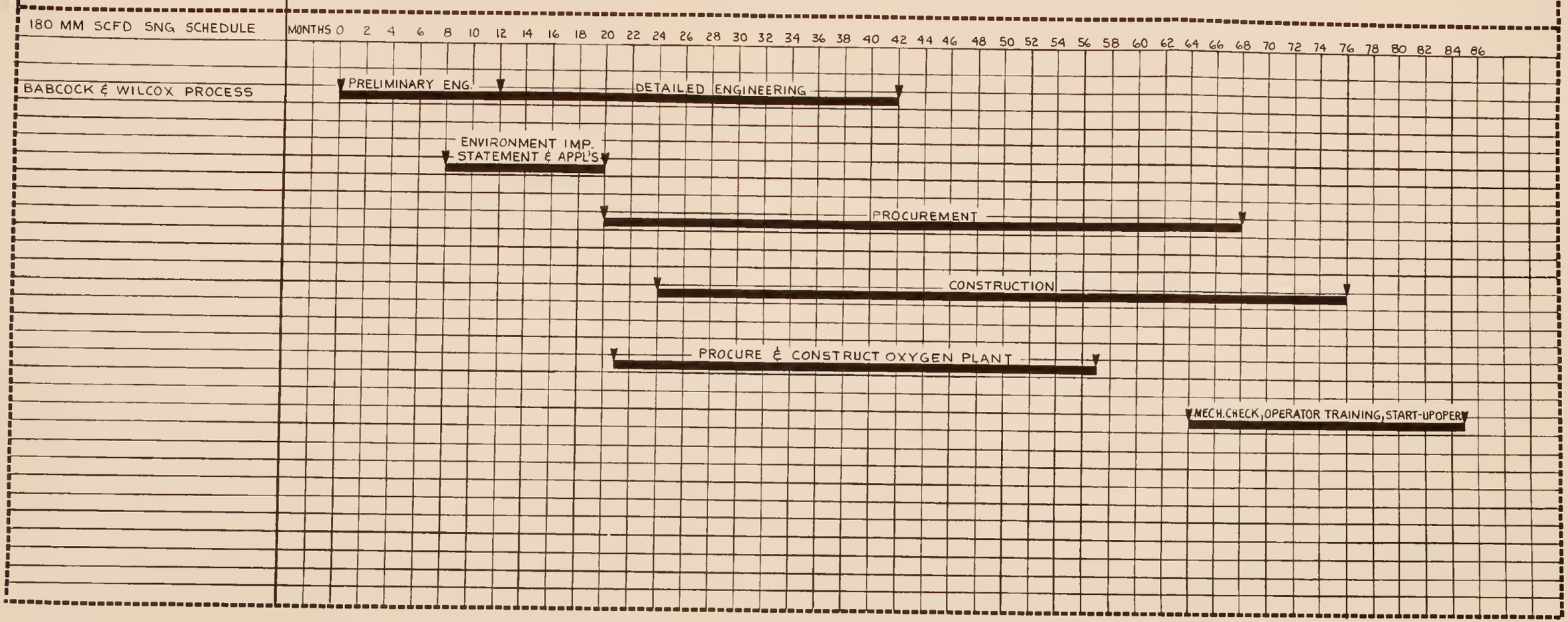
CHEMICAL PLANTS DIV
SYNTHETIC FUELS DEPT.

CPD - 7024

PROJECT SCHEDULE



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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.2 CO_2 Acceptor

PROCESS DESCRIPTION

The CO_2 Acceptor process features two fluidized bed reactors: a coal gasifier and an acceptor regenerator. Both the gasifier and the acceptor regenerator are vertical cylindrical pressure vessels with nozzles for feed inlet and product outlet. The dolomite, which is the selected acceptor is recirculated between the gasifier and the regenerator. In the regenerator it is calcined to form CaO, and in the gasifier it reacts with CO_2 exothermally by the "acceptor reaction." The reactions are:

$$CaCO_3 \longrightarrow CaO + CO_2$$

$$CaO + CO_2 \longrightarrow CaCO_3$$

Heat released by the exothermic acceptor reaction in the gasifier carries out the carbon-hydrogen gasification reactions and coal devolatilization, and eliminates the need for pure oxygen to produce a 300 + Btu/SCF gas. Two trains of the gasifiers and regenerators are needed to produce the 150 MM SCFD of SNG and the gas required for 1000 TPD of ammonia production.

The feed lignite is conveyed to a hot gas swept hammer mill, where it is crushed from minus 2-inch to minus 1/8-inch and dried to a 20 percent moisture content. Part of this partially dried lignite, along with the fuel gas recycled from the nitrogen wash column, is combusted in a

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.2 CO_2 Acceptor (Cont'd.)

furnace, and the hot flue gases produced provide the heat to dry the incoming lignite feed. The balance of the lignite flows to flash dryers where it is dried to 5 percent moisture. This dried lignite is then reduced to zero moisture as it is heated to 500°F in a fluidized preheater and fed to the gasifier using a lock hopper injection system.

The dolomite feed is crushed in a hammer mill to minus 4 mesh. A double deck screen separates oversize and undersize material, and the oversize material is recycled to the mill. The proper sized stone (minus 4 to plus 14 mesh) is sent to the dolomite feeding system for injection into the regenerator. This make-up dolomite enters the regenerator with spent dolomite from the gasifier, and both are calcined and then recirculated to the gasifier.

The lignite is fed from the lock hopper to the gasifier along with reaction steam and calcined acceptor (dolomite) from the regenerator. In the gasifier, the acceptor reacts exothermally by the CO_2-acceptor reaction. The CO_2-laden acceptor is pneumatically recycled to the regenerator where CO_2 is removed by heat supplied by burning char formed in the gasifier.

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.2 CO_2 Acceptor (Cont'd.)

The hot regenerator off gas, consisting mainly of CO_2 and N_2, flows through the cyclones, where entrained ash and dolomite are separated from the gas, to the waste heat boiler, where 185 psig, 1200°F steam is generated. The off gas is thus cooled from 1860°F to 1160°F. The off gas is then combusted in a CO burner, and the resulting hot gas flows to the power recovery gas expanders at 1420°F and 125 psig. Sufficient power is generated to operate the regenerator air compressor and the lift gas compressor, which transports the spent dolomite to the regenerator. The gas is further cooled to 150°F in another waste heat boiler and then is available for use as an inert process gas.

The raw product gas from the gasifier is passed through a cyclone, cooled in a waste heat recovery system, and fed to a quench tower in which any ammonia formed during gasification is removed.

The raw product gas leaves the gasifier at an H_2S content of 200 ppm. The remainder of the sulfur was chemically combined with a portion of the circulating dolomite. The sulfided dolomite is inert to heat regeneration, making it necessary to treat this material in a separate process. The dolomite also has with it the ash formed by the combustion of char in the regenerator. This dolomite, due to its sulfur content, is unacceptable as landfill and must be further treated in the Chance

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.2 CO_2 Acceptor (Cont'd.)

process. Here the solid waste is slurried with water and fed to the Chance reactors at 35 percent solids. The CO_2-rich acid gas separated in the acid gas removal step is also injected into the reactors, and the CO_2 reacts with the sulfide to produce a carbonate and H_2S:

$$CaS + H_2O + CO_2 \longrightarrow CaCO_3 + H_2S$$

Thus, the acid gas H_2S content is concentrated, while the calcium sulfide is converted to carbonate. The off gas from the Chance process contains over 24% H_2S and can be treated in a Claus-SCOT combination plant in which elemental sulfur is recovered as a by-product. The carbonate is sent to landfill along with the ash.

The raw product gas from the quench tower enters a Benfield acid gas removal system at 230°F and 135 psig. The purified gas exits the acid gas adsorber with its H_2S and CO_2 contents reduced to 2 ppm and 1 percent, respectively. The acid gas stream produced in the Benfield system serves as the source of CO_2 for the Chance reactors.

A sidestream of the purified gas is compressed to 500 psig and taken off as feed to the liquid nitrogen wash section of the ammonia plant. Two streams are returned from the liquid nitrogen wash section to the gasification plant: a fuel gas stream for coal preparation and a methane rich stream to the inlet of the cold gas recycle methanator.

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.2 CO_2 Acceptor (Cont'd.)

The latter stream is combined with the remaining purified gas out of the Benfield system, compressed to 225 psig, and fed to methanation at a 3.1:1 hydrogen to carbon monoxide ratio. In the methanation step, 99.9 percent of the CO in the feed gas is converted to methane. The resulting SNG is then compressed and dehydrated in a glycol dehydration unit. The product gas enters the product gas line at 1000 psig and 100°F. Surge bottles are provided on the product gas to smooth out minor process upsets.

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.2 CO_2 Acceptor (Cont'd.)

TECHNICAL EVALUATION

Montana Lignite:

The CO_2 Acceptor pilot plant has operated mostly on lignites with the balance of their runs made using a sub-bituminous feedstock. No Montana lignites have yet been processed in the unit. The longest steady state run to date on the pilot plant unit has been seven days. The process cannot operate on any coal containing more than three weight percent silica on a dry coal basis.

Degree of Development and Technical Risk:

The CO_2 Acceptor pilot plant, located in Rapid City, South Dakota, is capable of processing 30 TPD of lignite feed. Since its dedication in August, 1972, the pilot plant has logged thousands of hours of on-stream time. Significant progress has been made in improving system reliability, which was a severe problem in the early history of the plant. Proper distribution of the solids in the gasifier and regenerator is essential for satisfactory operations. It has been satisfactory with the 40-inch I.D. gasifier, however, with scale-up versions it may very well be a problem. Conoco favors the construction of a "cold model" to study the distribution. Although the relatively low system operating

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.2 CO_2 Acceptor (Cont'd.)

pressure helps keep the risk factor down, the combination of unproven technology and high equipment scale-up factor results in a relatively high technical risk factor.

Operability and Start-Up:

Due to the repetitive heating and cooling cycles the pilot plant vessels have experienced (over 200 cycles), the regenerator has lost some refractory. In a commercial plant this will not be a serious problem because shutdowns will be less frequent.

Hot, particle-laden gas at high pressure emerges from the regenerator. Removing the dust and extracting power and steam from the potential energy of the gas in trouble-free equipment before the gas is exhausted to the atmosphere is essential for high process efficiency. Various schemes are being considered, and C. F. Braun has been contracted to study these schemes.

Accumulation of intermediate size particles in the recirculating solids had been a problem, however it has been solved by purging the spent dolomite from the regenerator instead of the gasifier boot. In this manner, the intermediate size particles leave with the spent dolomite. To maintain the purging rate of the dolomite at a reasonable level, the silica in the coal responsible for the intermediate size particles has to be limited to 3% on a dry basis.

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.2 CO_2 Acceptor (Cont'd.)

Gasifier Scale-Up:

The gasifier scale-up factor assumed for this study is over 250 and represents a high risk scale-up.

Carbon Conversion:

99.4%

Overall Thermal Efficiency:

64.8%

Mechanical Reliability:

Equipment must be designed so that it will permit trouble-free solids flow and distribution in the gasifier and regenerator. A reliable method of recovering power from the dust-laden hot regenerator off-gas must be established. Erosion of the power recovery turbine components is the main anticipated problem.

By-Products:

Claus plant sulfur of 95% minimum purity is recovered as a salable by-product.

Environmental Considerations:

The plant is designed for compliance with established emission and disposal regulations. Acceptor blowdown is treated for sulfide removal prior to being sent to landfill.

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.2 CO_2 Acceptor (Cont'd.)

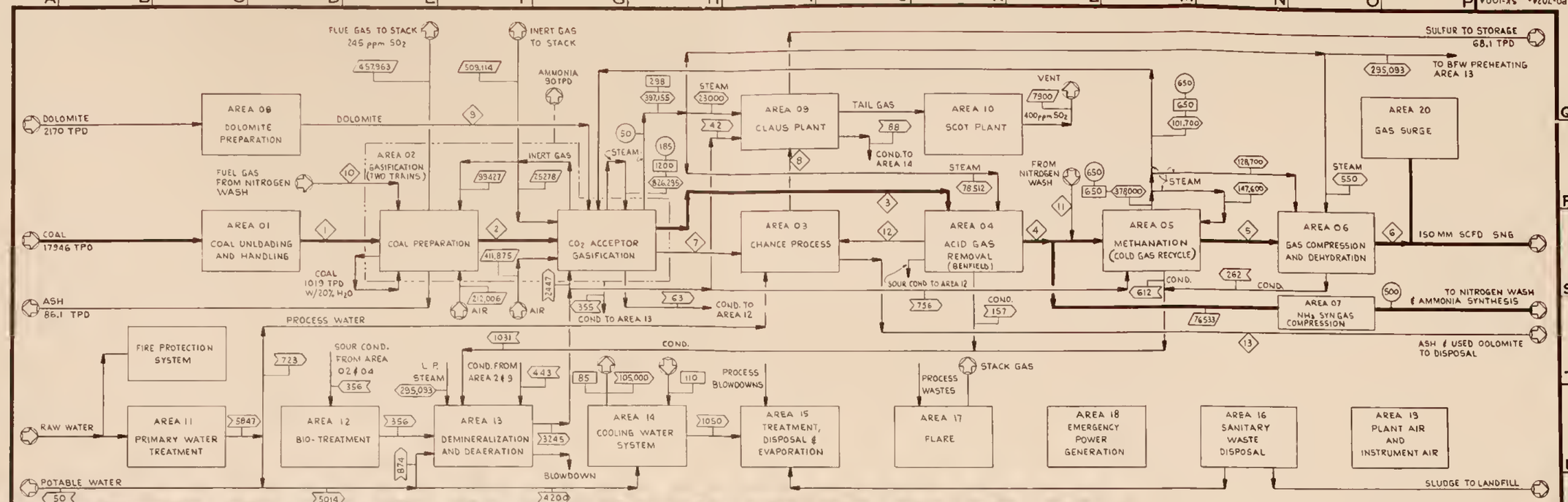
Licenses and Guarantees:

Since the process has been developed using government funds and all information is public, no licenses are required and no guarantees are available.

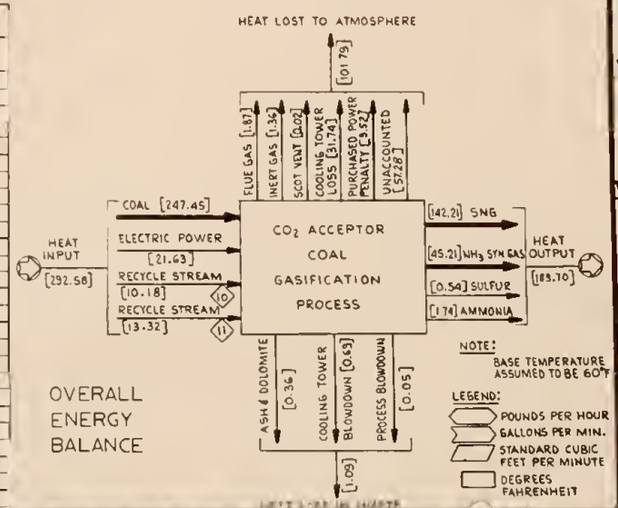
Flexibility and Turndown:

The CO_2 Acceptor gasifier accepts lignites and sub-bituminous coals, but not agglomerating coals. Also, to be acceptable, the coal must have less than 3% silica content on a dry basis.

Being a fluidized bed system, it is expected the gasifier and regenerator can be turned down to 25% of the nominal capacity. Also, since two such parallel systems are used for the present design, by shutting down one system, a turndown lower than 25% can also be achieved.



MATERIAL / STREAM No.	1	2	3	4	5	6	7	8	9	10	11	12	13
COMPOSITION	WT %	WT %	MOL. %	MOL %	MOL %	MOL %	WT %	MOL. %	WT %	MOL. %	MOL %	MOL. %	WT %
MAF COAL	58.12	89.44											
ASH	6.86	10.56											
MOISTURE	35.02	—											
CO			16.95	20.28	1.30	1.31				54.71	21.87		
CO_2			4.08	1.00	2.03	2.04		65.95				93.74	
CH_4			11.31	13.53	91.94	92.34				9.01	71.78		
H_2			53.60	64.11	3.45	3.46				9.26	3.61		
$H_2S + COS$			0.02	2 PPM	TRACE	—		24.63				0.58	
$N_2 + Ar$			0.18	0.22	0.84	0.84				27.02	2.74		
H_2O			13.86	0.86	0.44	0.01		9.42				5.68	55.68
$MgCO_3 \cdot CaCO_3$									100.00				25.33
$MgO \cdot CaO$							21.57						
$MgO \cdot CaCO_3$							24.67						
$MgO \cdot CaS$							0.21						
CaS							5.23						
$CaCO_3$													2.48
INERT + CARBON							48.32						16.51
HHV BTU/SCF (DRY)			398.1	413.8	948.2	948.2				296.9	807		
TOTAL LB MOLS/HR			62874	52559	16558	16,487		724		3767	1811	2176	
TEMPERATURE °F	AMB.	500	230	100	100	100	466	125	AMB	100	100	100	
PRESSURE PSIG	ATM.	ATM	135	95	210	1000		6	ATM	5	5	2	
MM SCFD			571.9	478.1	150.6	150.0		6.6		34.3	16.5	19.8	
TPD	17,946	10,846					2671		2170				7815



$$\% \text{ O.A. THERMAL EFFICIENCY} = \frac{\text{HEAT OUTPUT}}{\text{HEAT INPUT}} \times 100 = \frac{189.70}{292.58} \times 100 = 64.83\ \%$$

DESIGNED	RGN	8-3-76
DRAWN	DAP	8-6-76
CHECKED	RGN	10-19-76
APPROVED		
APPROVED		
APPROVED		

TITLE: PROCESS BLOCK FLOW DIAGRAM CO_2 ACCEPTOR COAL GASIFICATION

FOR: MONTANA TRADE COMMISSION

Dravo CORPORATION
Chemical Plants Division · Pittsburgh, Pennsylvania

SCALE: —/—

DRAWING NUMBER: CPD-7024-SK-100A

REV.

REV | DESCRIPTION | MADE | CHKD | DATE | REV | DESCRIPTION | MADE | CHKD | DATE

NO. | REV. | RELEASED FOR | APP | DATE

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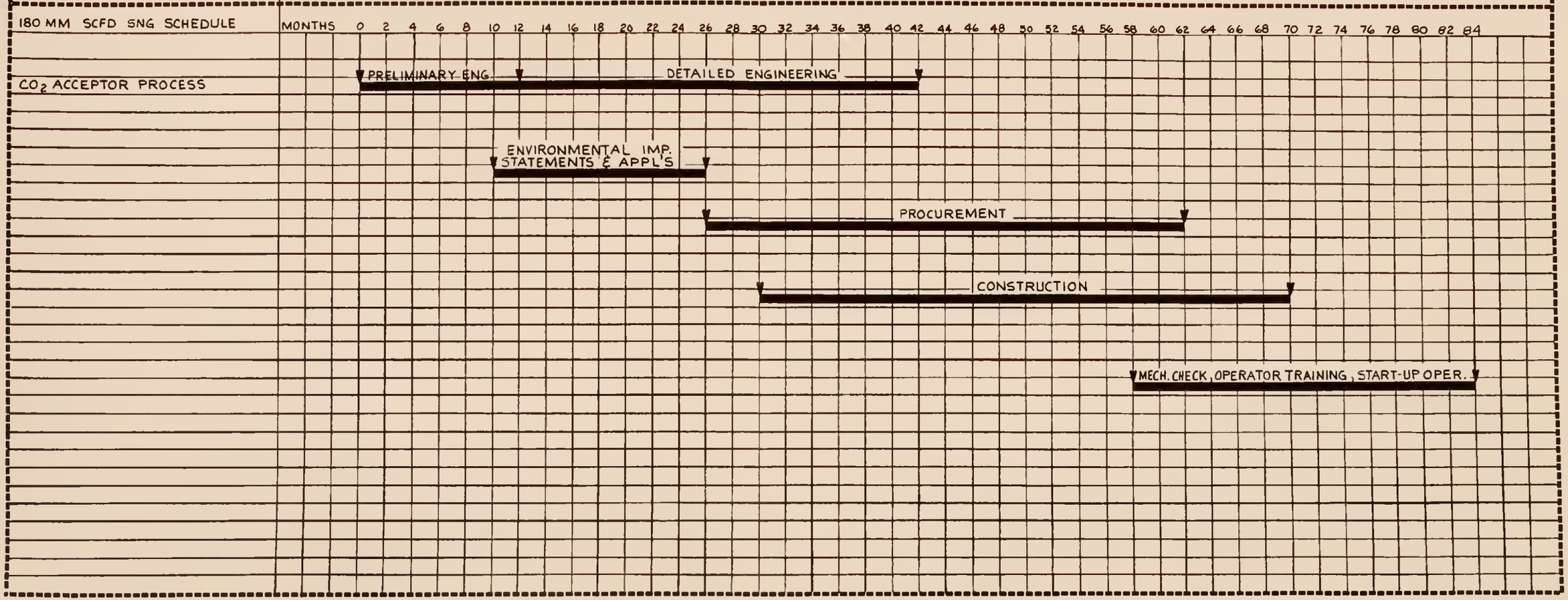
CHEMICAL PLANTS DIV.
SYNTHETIC FUELS DEPT.

CPD - 7024

PROJECT SCHEDULE



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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.3 COGAS

PROCESS DESCRIPTION

The COGAS process employs multi-stage pyrolysis to convert the lignite feed into a raw oil by-product and gas. The char exiting the pyrolysis area is then fed to the gasifier to produce an additional amount of gas. The heat required for gasification is supplied by burning a part of the char fines in a separate combustor while recirculating the remaining fines to the gasifier. This eliminates the need for an oxygen plant. Two trains of pyrolyzers and gasifiers are needed to produce the 150 MM SCFD of SNG and the gas required for 1000 TPD of ammonia production.

The lignite is dried to remove its surface moisture before it is crushed from minus 2" to minus 1/8", the required feed size. The crushed lignite is conveyed by a belt conveyor to a hold bin, from where it is pneumatically transported to fluidized coal dryers. Hot flue gases from the combustor are used to further dry the lignite to the desired moisture level and to heat the lignite fed to the pyrolysers. The cooled flue gases leaving the dryers are scrubbed for SO_2 removal before they are vented to the atmosphere.

The dried lignite is pneumatically conveyed to the series of fludized bed pyrolyzers. Each bed is operated at an increasingly higher temperature,

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.3 COGAS (Cont'd.)

resulting in the devolatilization of the lignite. The gas produced in gasifier serves as the fluidizing medium. The fluidizing gas, along with the volatiles from pyrolysis, are water-quenched in a venturi scrubber on exiting the final stage of pyrolysis, condensing most of the oils and water out of the product gas. The sour water stream formed is processed for the recovery of ammonia and sulfur. The oil condensate is hydrotreated with hydrogen generated from a sidestream of product gas. This refined syncrude is sent to storage.

The cooled product gas is compressed and passed through a Selexol system where all of the H_2S and part of the CO_2 are removed. The separated acid gas is treated in a Stretford unit for elemental sulfur recovery. The purified gas then enters an oil scrubbing system in which any light hydrocarbons in the gas are recovered as a by-product.

The gas leaving the oil scrubber is divided into a small stream to hydrogen production for raw oil treatment and the CO shift feed and bypass. The CO shift feed is heated prior to entering the first stage reactor. The exit gas is recombined with the bypass and is split again - one stream going to the ammonia plant and the other proceeding to a cold gas recycle methanation unit. A fuel gas stream is returned from the nitrogen wash column for coal drying. In the methanation unit,

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.3 COGAS (Cont'd.)

99.9 percent of the feed CO is converted to methane. The methanated gas is purified by removing 98% of the CO_2 in a Selexol unit. The purified gas is compressed to pipeline pressure and then dehydrated in a glycol dehydration unit. The product gas enters the product gas line at 1000 psig and 100°F. Surge bottles are provided on the product gas line to smooth out minor process upsets.

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.3 COGAS (Cont'd.)

TECHNICAL EVALUATION

Montana Lignite:

The pyrolysis pilot plant has been operated on lignite mined from the Glen Harold seam located on the North Dakota-Montana border. Reproducible material balance runs were completed. The char out of pyrolysis was gasified in a bench scale unit without any problems. Excess fines were formed, but this was caused by the grinder, which was designed for bituminous coals. A lignite grinder would minimize the fines formed. The pyrolysis section has been operating on many other coals, including caking coals. The pilot plant gasifier has processed Illinois No. 6 char with no difficulty.

Degree of Development and Technical Risk:

The pyrolysis pilot plant has processed some 30,000 tons of various coals at a design capacity of 36 TPD. A gasifier pilot plant has been constructed at BCURA in Leatherhead, England, handling 50 TPD of char produced in the pyrolysis unit. This unit has had continuous runs of 100 hours, ninety of which were self-sustained.

The pyrolysis pilot plant has been well demonstrated and data gathered have been consistent and reproducible. This section is deemed ready for commercialization.

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.3 COGAS (Cont'd.)

The gasifier plant has been piloted, but has not yet been integrated either with the pyrolysis unit or with the downstream upgrading processes required for 925+ Btu/SCF SNG production. The gasifier is an assemblage of fluid beds, pneumatic lift legs and cyclones. This technology is well established, but a steady state operation under varying loads and its capability to produce a specified gas output needs to be demonstrated. It is expected that this can be achieved. The pilot plant at BCURA has been operated to demonstrate the composition of the gas and preparations are currently being made for runs longer than 100 hours. The extensive data required for detailed design of the plant can be obtained, since the pilot plant is intact and available for further data gathering. The Gasification plant at BCURA represents a plant processing char resulting from 200 TPD of coal, although most runs to date have been at a lower rate equivalent to about 100 TPD.

Operability & Start-Up:

The COGAS gasification system contains a number of operations which are extensions of current technology. These include the fluid bed pyrolyzers and gasifiers, oil de-ashing, and circulating solids legs. Successful operation of these process steps will require an operator learning period. Until the operation of each unit and its interrelations are well understood by the operating staff, the plant can be expected to experience

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.3 COGAS (Cont'd.)

some upsets. The pilot plant has been able to come on and off stream without problems at BCURA and similar problems are not expected in commercial operation.

The units, with the exception of the hydrodesulfurization system, all operate at a fairly low pressure and do not pose any safety problems at steady state. During start-up and shutdown, care must be exercised to purge equipment of hydrocarbons to avoid explosive conditions. This is also true of the large inventory of hot coal in the pyrolyzers and gasifiers.

The high pressure of hydrodesulfurization requires careful attention in the design, operation and maintenance of this system.

The plant will require extensive instrumentation for efficient operation. The major problem in this area is the metering of solids between the pyrolysis and gasification beds and reliable measurement of levels in the fluid beds.

Gasifier Scale-Up:

The pilot work supporting the gasification process has been on the scale of 50 TPD of char at BCURA, Leatherhead, England, while pyrolysis is demonstrated on the 36 TPD of coal unit at Princeton, New Jersey. A

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.3 COGAS (Cont'd.)

scale-up ratio of 300 for pyrolysis and 120 for gasification are deemed high even considering their demonstrated operability.

Carbon Conversion:

The carbon conversion is 99.9%.

Overall Thermal Efficiency:

The overall thermal efficiency is 58.1%.

Mechanical Reliability:

The operation of the pilot plant pyrolysis section has been very dependable. It is deemed that along with some additional data obtained from tests on the selected lignite this portion of the plant can be designed from existing pilot plant data.

Since there are no moving parts in the gasifier and it operates at relatively low pressures, mechanical reliability is considered high. The circulation of large quantities of hot and possibly abrasive char presents the greatest mechanical problem in operating the gasifier. This problem can be minimized by careful selection of materials of construction and be designing to permit highly vulnerable elements to be readily replaced. This has been demonstrated at the BCURA pilot plant.

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.3 COGAS (Cont'd.)

By-Products:

Syncrude produced in the process is a low sulfur, high grade hydrogenated crude oil which should sell for a higher price than crude oil. The C_2-C_4 cut produced is also a high quality, marketable material. Ammonia and sulfur are also recovered as salable by-products. The C_2-C_4 material also provides flexibility in upgrading SNG fuel value as desired.

Environmental Considerations:

The plant is designed to comply with established emission regulations.

Licenses and Guarantees:

COGAS Development Company will offer process guarantees for the gasifier and pyrolyzers. All license fees are charged on a running basis. These fees are subject to further definition and negotiation with COGAS Development Company.

Flexibility and Turndown:

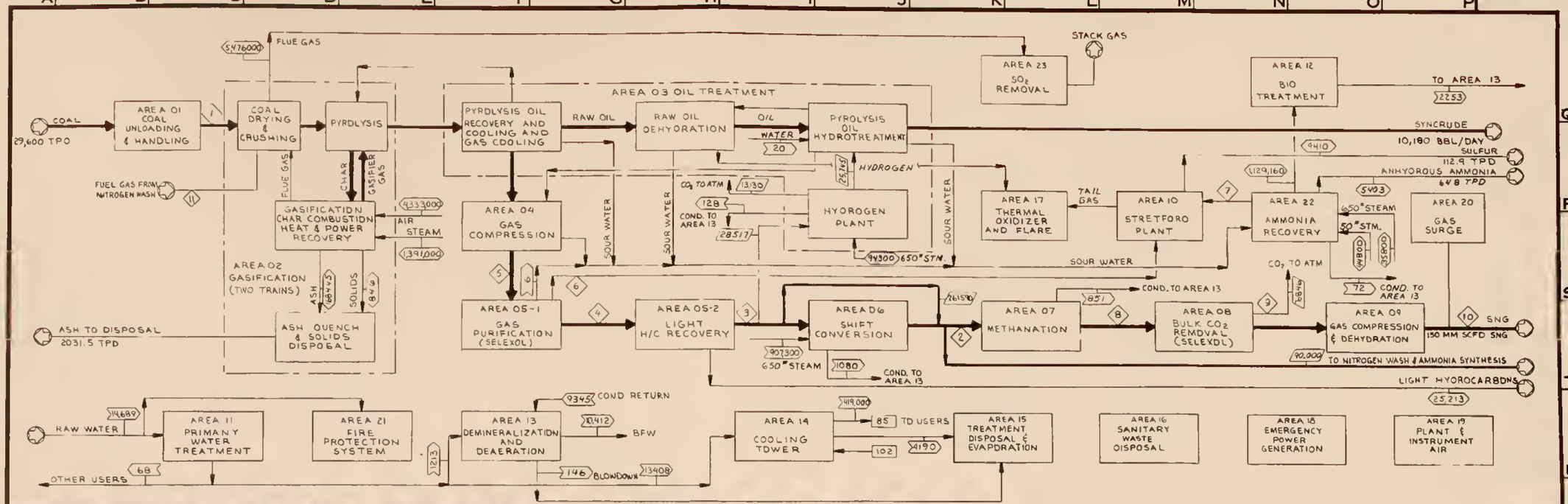
The gasifier accepts all types of coal. The pyrolysis section has been operated on different American bituminous, sub-bituminous, and lignite coals. The gasification section has also been run on various chars, including those from bituminous and lignite coals.

7.0 FINAL PROCESS EVALUATION (Cont'd.)

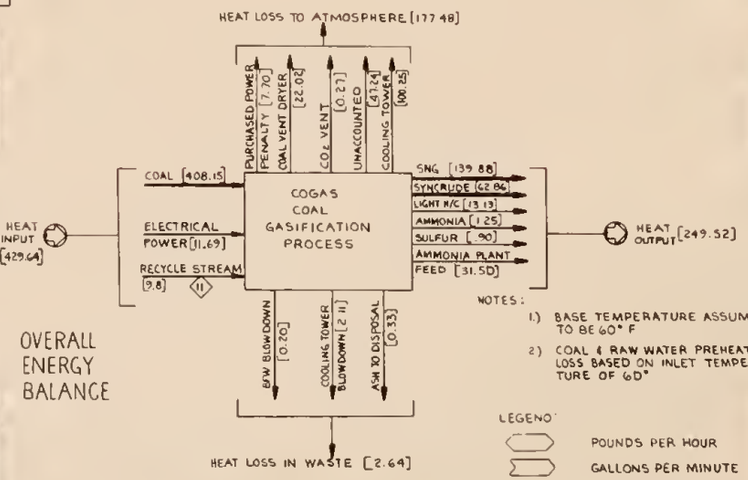
7.2 Description and Technical Evaluation (Cont'd.)

7.2.3 COGAS (Cont'd.)

Turndown of the multistage pyrolyzers has not been established. It will be limited by minimum gas flow required for fluidization. The plant can be further turned down if necessary by shutting down one of the two pyrolyzer-gasifier trains.



MATERIAL / STREAM No	1	2	3	4	5	6	7	8	9	10	11
COMPOSITION	WT %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %
MAF COAL	58.12										
ASH	6.86										
MOISTURE	35.02										
CO		16.76	32.78	32.45	31.25			0.05		0.08	70.66
CO_2		13.56	8.59	8.50	11.12	83.0		42.42	97.73	1.47	
CH_4		1.97	2.52	2.50	2.40			52.33		90.71	8.30
H_2		51.95	55.16	54.61	52.60			2.39		4.14	1.86
$H_2S + COS$				TRACE	0.29	10.2	94.4				
$N_2 + Ar$		0.75	0.95	0.95	0.91			2.06		3.58	19.18
O_2											
H_2O		13.01		0.16	0.63	6.8	5.6	0.75	2.27	0.02	
LIGHT HYDROCARBONS (C_2C_6)											
				0.83	0.80						
HHV BTU/SCF (DAY)		279.1	310.3	326.4	317.6					932.7	317.6
TOTAL LB MOLES/HR		79067	77,429	78212	81213	2874	62	28,600	12,166	16,499	3380
TEMPERATURE (°F)		300	86	100	150	110	104	150	70	100	100
PRESSURE (PSIG)		500	540	560	575	5	4	480	1	1000	5
MMSCFD		719.2	704.3	711.4	738.8	26.1	0.56	260.1	110.7	150.0	76.85
TPD	29,600										



OVERALL ENERGY BALANCE

NOTES:

1.) BASE TEMPERATURE ASSUMED TO BE 60° F

2) COAL & RAW WATER PREHEATING LOSS BASED ON INLET TEMPERATURE OF 60°

LEGEND

- POUNDS PER HOUR
- GALLONS PER MINUTE
- STANDARD CUBIC FEET PER MINUTE
- DEGREES FAHRENHEIT
- PSIG
- [ ] BILLION BTU'S PER DAY

$$\%\ O.A.\ \text{THERMAL EFFICIENCY} = \frac{\text{HEAT OUTPUT}}{\text{HEAT INPUT}} \times 100 = \frac{249.52}{429.64} \times 100 = 58.08\ \%$$

REV	DESCRIPTION	MADE	CHKD	DATE	REV	DESCRIPTION	MADE	CHKD	DATE

NO.	REV.	RELEASED FOR	APP.	DATE

DESIGNED	K M	8-3-76
DRAWN	M.C. PAT	8-26-76
CHECKED	RGN	10-19-76
APPROVED		
APPROVED		
APPROVED		

TITLE: PROCESS BLOCK FLOW DIAGRAM
COGAS COAL GASIFICATION
100×10^9 BTU/DAY

FOR: MONTANA TRADE COMMISSION

Dravo CORPORATION
Chemical Plants Division - Pittsburgh, Pennsylvania

SCALE: —//—

DRAWING NUMBER: CPD-7024-SK-100C

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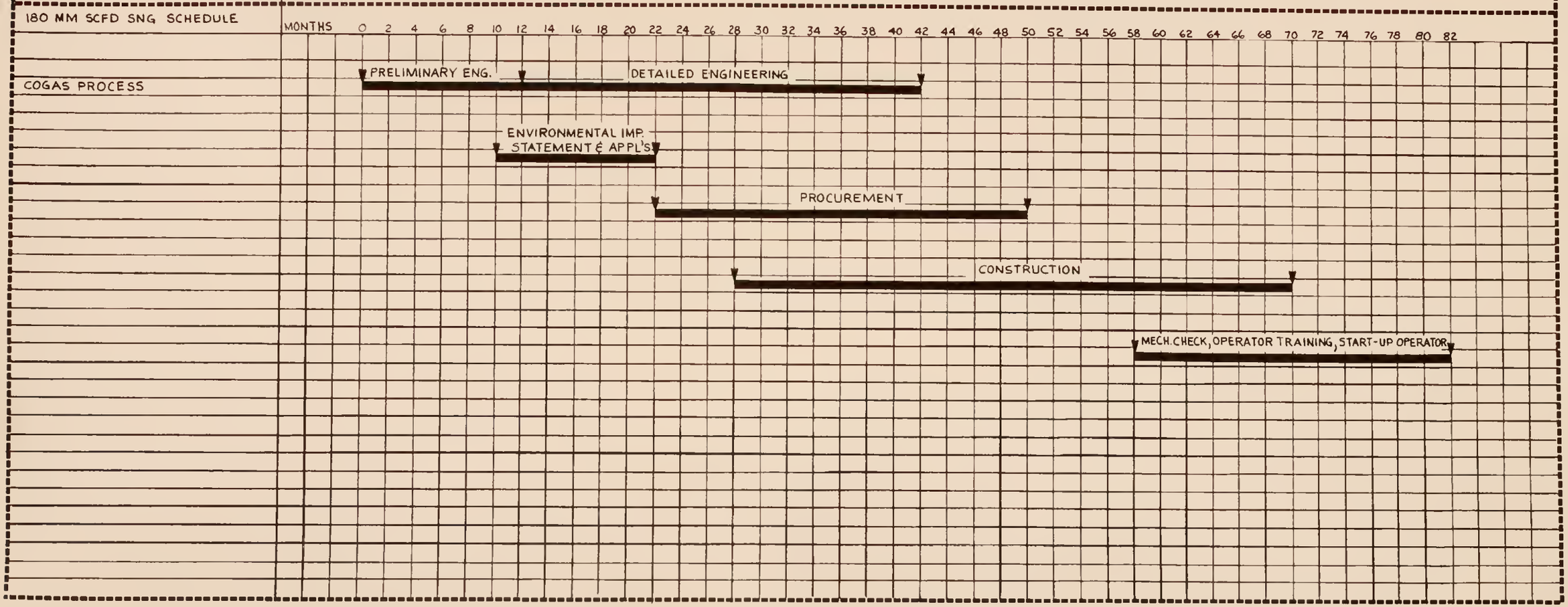
CHEMICAL PLANTS DIV.
SYNTHETIC FUELS DEPT.

CPD - 7024

PROJECT SCHEDULE



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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.4 HYGAS

PROCESS DESCRIPTION

The HYGAS gasifier consists of a vertical shell containing four gas-solid contacting stages, internally connected by transfer lines. The four sections from top to bottom are: slurry drying, first-stage hydrogasification, second-stage hydrogasification, and steam-oxygen gasification.

The feed lignite is introduced into the gasifier in the form of a lignite-water slurry. The water is driven off in the slurry drying section with gases leaving the stages below. In the first- and second-stage hydrogasification, the carbon-hydrogen reaction is promoted to produce methane exothermally. This heat is utilized to decompose steam on carbon to produce hydrogen in addition to that produced in the steam-oxygen gasification section, where char leaving the second hydrogasification stage is gasified in the presence of steam and oxygen. Ash is removed from the bottom and sent to disposal. The methane-rich gases formed leave the gasifier at the top. Two gasifiers with 18 ft. maximum diameter and 215 ft. height are needed to produce the 150 MM SCFD of SNG and the gas required for 1000 TPD of ammonia production.

The lignite dried to 10 percent moisture is crushed to minus 8 mesh. Flue gas from a coal fired heater provides the heat for lignite drying and the gas leaving the dryer is treated for SO_2 removal before being

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.4 HYGAS (Cont'd.)

released to the atmosphere. The processed lignite is then mixed with water, producing a 53 percent solids slurry. The slurry is heated to 570°F in an external heater, and pumped into the gasifier. Simultaneously, oxygen at 370°F and superheated steam at 1000°F are fed into the steam-oxygen section of the gasifier.

The raw product gas, after drying the feed slurry, exits the top of the gasifier at 600°F. This raw gas is water quenched at 465°F prior to CO shifting. In the shift reactor, a high sulfur cobalt-moly catalyst is used, thus eliminating the need for H_2S removal before shifting, and consequently, eliminating the need for cooling the gas down below 465°F. The quenched gas is split into two streams: 71 percent of the gas passes through the shift reactors while the remainder is bypassed. These streams are recombined after the shift and cooled down to 100°F by generating steam and by indirect contact with cooling water. A BTX fraction condenses out of the gas and is recovered as a byproduct. Ammonia in the gas also comes out in the condensed water. The water is processed and distilled to recover anhydrous ammonia.

The cooled gas enters a Selexol system in which essentially all of the H_2S and CO_2 are removed from the feed gas. This acid gas stream is sent to a Stretford plant where elemental sulfur is recovered as a byproduct. The purified gas exits the acid gas absorber at 100°F and 1145 psig.

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.4 HYGAS (Cont'd.)

A sidestream of this purified gas is diverted to the liquid nitrogen wash section of the ammonia plant. The main stream proceeds to a cold gas recycle methanation unit. Two streams are returned from the liquid nitrogen wash section to the gasification plant: a fuel gas stream to the plant boiler and a methane rich stream to the inlet of the methanator to be combined with the main stream. The total feed to methanation contains hydrogen and carbon monoxide in a 3.1:1 ratio. In the methanation step, 99.9 percent of the CO in the feed gas is converted to methane. The resulting SNG is then dehydrated in a glycol dehydration unit. Compression is not required because the gas is available at the specified 1000 psig pressure. Surge bottles are provided on the product gas line to smooth out minor process upsets.

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.4 HYGAS (Cont'd.)

TECHNICAL EVALUATION

Montana Lignite:

The HYGAS pilot plant has successfully operated on Montana lignite. A 30-day run utilizing purchased hydrogen and a 15-day run using the steam-oxygen gasifier as the hydrogen source have been completed. Both runs were voluntarily terminated.

Degree of Development and Technical Risk:

A detailed lignite testing program has been completed at the 75 TPD HYGAS pilot plant. Bituminous coals have also been tested. Present plans call for a sub-bituminous test program to begin in the near future. The reactor is designed for 1500 psig operation and in the past has had problems with internal solids movement. IGT believes that these problems are solved. Commercialization of this new high pressure technology involves a high risk factor. Duplication of results of pilot plant operations on lignite would ensure a good basis for a commercial design.

Operability and Start-Up:

Internal solids movement at high pressure, the complexity of the reactor design, the slurry feed system and internal steam-oxygen gasification of char represent possible operating problems. However, IGT

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.4 HYGAS (Cont'd.)

believes that the pilot plant is completely operable and expects any commercial plant of similar design to be the same.

Gasifier Scale-Up:

The gasifier scale-up factor is in excess of 80. This, coupled with the intricate gasifier internals, makes it a high risk scale-up.

Carbon Conversion:

The carbon conversion is 93.7%.

Overall Thermal Efficiency:

Overall thermal efficiency is 69.8%.

Mechanical Reliability:

The slurry feeding system, internal solids transfer, and high pressure operations present erosion problems. Compressing large quantities of oxygen to very high pressure also presents a considerable mechanical problem.

By-Products:

A benzene-toluene type aromatic material is produced as a by-product along with ammonia and sulfur. The products are expected to be of good quality and salable.

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.4 HYGAS (Cont'd.)

Environmental Considerations:

The plant is designed for compliance with established emission and disposal regulations.

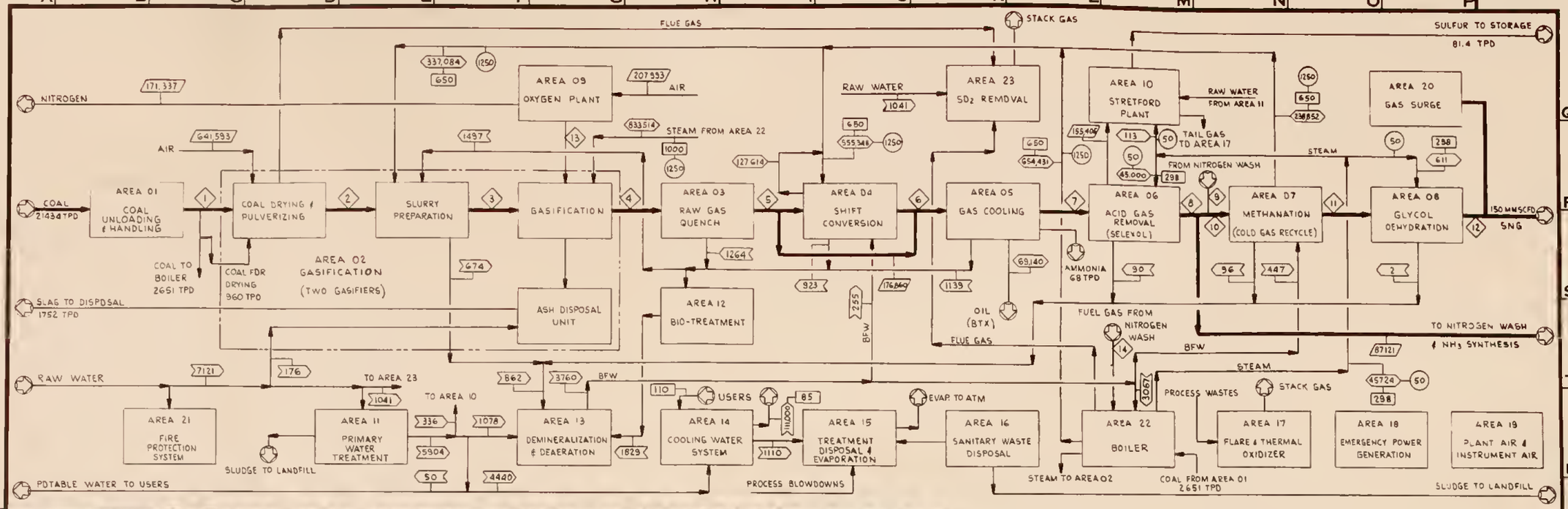
Licenses and Guarantees:

HYGAS is being developed by IGT under a contract from ERDA and AGA. Information for design would be available to qualified interests at no cost. Accordingly, no process guarantees are provided.

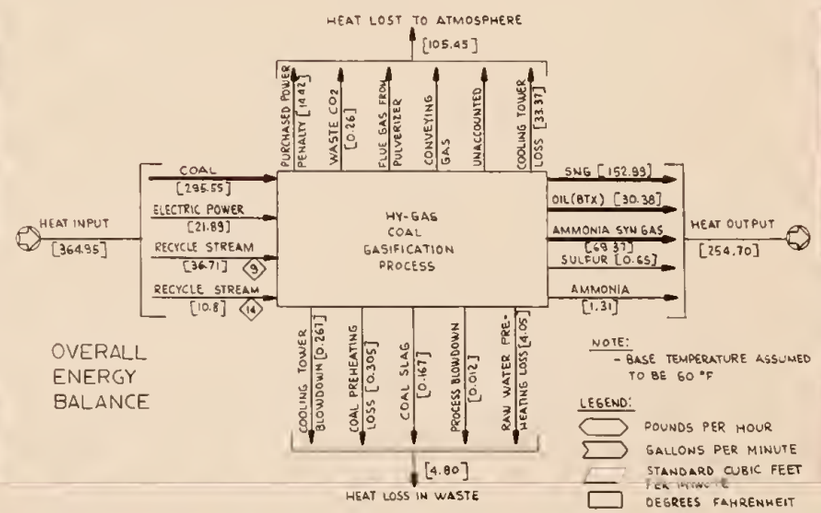
Flexibility and Turndown:

The HYGAS gasifier is expected to accept all types of coal. The agglomerating bituminous coal will need pretreatment. The gasifier has been tested mostly on lignite coals. Runs on sub-bituminous and bituminous coals are underway.

Turndown of the multi-stage HYGAS gasifier has not been determined. With two gasifiers available for the present SNG plant, a further turndown is possible by shutting down one of the two gasifiers.



MATERIAL \ STREAM No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14
	WT %	WT %	WT %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %
MAF COAL	58.12	80.50	42.67											
ASH	6.86	9.50	5.04											
MOISTURE	35.02	10.00	5.29											
CO				9.84	13.02	5.65	8.44	13.74	21.81	14.57	0.14	0.14		46.87
CO_2				13.56	17.80	25.57	38.21	—	—	—	—	—		—
CH_4				3.32	12.33	12.49	18.56	30.38	72.14	36.80	93.55	93.63		45.52
C_2H_6				0.46	0.61	0.61	0.32	1.50	4.22	1.91	3.45	3.46		0.7
H_2				11.00	14.55	22.27	33.27	54.16	1.48	46.08	2.51	2.51		3.29
$H_2S + COS$				0.19	0.24	0.25	0.37	2 PPM	—	—	—	—		
$N_2 + Ar$				0.03	0.04	0.04	0.06	0.10	0.35	0.14	0.25	0.25	0.5	3.62
O_2								—	—	—	—	—	99.5	—
H_2O			47.00	54.65	40.25	31.93	0.07	0.12	—	0.10	0.10	0.01		—
HCl				TRACE	TRACE	TRACE	—	—	—	—	—	—		—
NH_3				0.32	0.34	0.35	—	—	—	—	—	—		—
HCN				0.02	0.02	0.03	—	—	—	—	—	—		—
LIGHT HYDROCARBONS				0.61	0.80	0.81	—	—	—	—	—	—		—
HHV (BTU/SCF) DRY				163.6	224.5	227.5	340.0	553.6	878.2	603.3	1014.5	1015.5		623.8
TOTAL LB MOLES/HR				127746.3	96548.3	95295.1	63788.6	39186.1	4545.6	23939.3	16557.4	16,543.3	580.30	1904.4
TEMPERATURE °F	AMB		570	600	465	365	100	100	100	100	200	100	370	100
PRESSURE, PSIG	ATM		1270	1250	1220	1180	1160	1145	5	1145	1120	1000	1270	5
MM SCFD				1161.58	878.2	866.8	580.2	356.4	41.8	272.9	150.8	150.7	52.8	17.3
TPD	17823	12868	2185										2228.5	



OVERALL ENERGY BALANCE

NOTE:
- BASE TEMPERATURE ASSUMED TO BE 60 °F

LEGEND:
- POUNDS PER HOUR
- GALLONS PER MINUTE
- STANDARD CUBIC FEET PER MINUTE
- DEGREES FAHRENHEIT
- PSIG
- [ ] BILLION BTU'S PER DAY

$$\% \text{ O.A. THERMAL EFFICIENCY} = \frac{\text{HEAT OUTPUT}}{\text{HEAT INPUT}} \times 100 = \frac{254.70}{364.73} \times 100 = 69.79\ \%$$

DESIGNED	HMJ	8-13-76
DRAWN	DAF	9-15-76
CHECKED	RGN	10-19-76
APPROVED		
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APPROVED		

TITLE: PROCESS BLOCK FLOW DIAGRAM
HY-GAS COAL GASIFICATION
FOR: MONTANA TRADE COMMISSION

Dravo CORPORATION
Chemical Plants Division · Pittsburgh, Pennsylvania

SCALE: —
DRAWING NUMBER: CPD-7024-SK-100H
REV.

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CHEMICAL PLANTS DIV.
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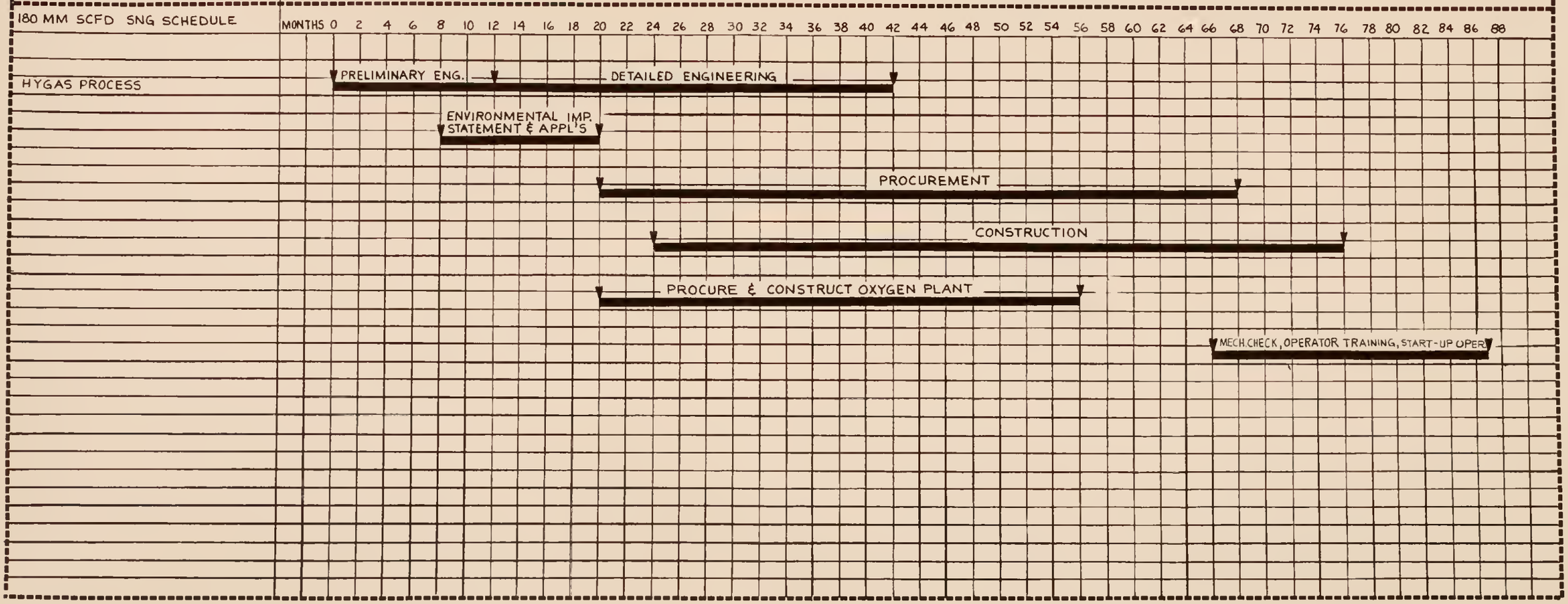
CPD - 7024

PROJECT SCHEDULE



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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.5 Koppers-Totzek

PROCESS DESCRIPTION

The Koppers-Totzek (K-T) entrained flow gasifier is horizontal and ellipsoidal in shape, with four sets of burners mounted on it, one set at the end of each axis. The shell has a double wall construction, the inner shell being lined with castable refractory. The annulus between the inner and outer shells is connected to a steam drum. Low pressure steam is generated here with the heat escaping through the refractory. The slag is removed from the bottom, and the product gas exits from the top of the gasifier. Twenty K-T gasifiers (four-headed) are needed to produce the 150 MM SCFD of SNG and the gas required for 1000 TPD of ammonia production.

The lignite feed is dried to 8 percent moisture and pulverized to 70 percent through 200 mesh. The processed lignite is pneumatically transported to storage bins provided with each gasifier. A variable speed screw feeder meters the lignite into mixing nozzles, where it is entrained in steam and oxygen and injected into the gasifier. Injection rates are above the speed of flame propagation. The use of multiple burners on each head provides improved turbulence and acts as a safety feature to insure continuous ignition should a burner fail.

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.5 Koppers-Totzek (Cont'd.)

The exothermic reaction between the lignite and oxygen takes place at about 3500°F and 7 psig. The endothermic water gas reaction reduces the temperature to about 2700°F. These high temperatures cause the ash in the lignite to liquefy. About half of this molten slag flows down the gasifier walls and drains into the slag quench tank while the remainder leaves with the exit gas. A water spray cools and solidifes this entrained slag, thus preventing it from adhering to the tubes in the waste heat boiler.

The raw product gas is further cooled by the production of 1500 psig saturated steam in the waste heat boiler. The steam is superheated to 900°F by combusting a sidestream of the syngas in a separately fired superheater.

The gas exits the waste heat boiler at 450°F and then is washed and cooled to 100°F in a series of venturi scrubbers and a packed cooler. Any solids collected in the recirculating water are removed from the system in slurry form, thickened, and transported to an ash pond for disposal.

The cooled, clean gas is compressed to 515 psig. This gas enters a Benfield acid gas removal system at 250°F, where essentially all of the H_2S and CO_2 are removed. The separated acid gas stream is fed to a Stretford plant where elemental sulfur is recovered as a byproduct.

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.5 Koppers-Totzek (Cont'd.)

The purified gas stream exits the acid gas absorber at 240°F and is heated by the CO shift product gas. A part of the purified gas is routed to the gasification area for coal drying and steam superheating. The remainder of the gas enters a zinc oxide guard catalyst bed where trace amounts of sulfur compounds remaining in the gas are removed. The gas stream is then split, 79% of the gas passing through CO shift while the remainder bypasses it. Amount of CO shifted is that to yield a 3.1:1 hydrogen to carbon monoxide ratio in the mixture when these two streams are recombined after shift. A sidestream taken off as the feed to the ammonia synthesis plant, and the remaining gas is fed to methanation at 300°F and 460 psig. A fuel gas stream is separated in the nitrogen wash column and recycled to the gasification area for coal drying and steam superheating.

In the cold gas recycle methanation unit, 99.9 percent of the carbon monoxide in the feed gas is converted to methane. This raw SNG is passed through another Benfield system where the CO_2 formed in CO shifting is removed. The CO_2 is vented to the atmosphere. The purifed SNG is dehydrated in a glycol dehydration unit and compressed 1000 psig. Surge bottles are provided on the product gas line to smooth out minor process upsets.

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.5 Koppers-Totzek (Cont'd.)

TECHNICAL EVALUATION

Montana Lignite:

All commercial installations of the Koppers-Totzek gasifier, with one exception, operated on lignite. The unit has not been run on Montana lignite, but computer simulations indicate no problems in its use. Better carbon conversion is obtained in this gasifier with lignite than with other coals. As an entrained bed slagging gasifier, it is capable of processing highly caking coals, but requires ash fusion temperatures below 2600°F, a condition satisfied by the lignite chosen for this study.

Degree of Development and Technical Risk:

The Koppers-Totzek two-headed atmospheric gasifier has been in commercial operation since the early 1950's in 15 plants in Europe, Asia and Africa. The gasifier can be considered commercial. Four-headed units, which were included in this study, should be in operation in India in early 1977. A pressure unit is under development in Europe, but will not be ready for 4 to 7 years.

Operability and Start-Up:

The commercial background of this unit supplies the information required to verify its operability. About half the ash in the gasifier feed is

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.5 Koppers-Totzek (Cont'd.)

carried overhead as fine particles containing appreciable amounts of carbon. This must be scrubbed out by use of venturi scrubbers to assure minimal fouling of downstream compressors and gas purification equipment.

The unit is highly automated for safety shutdown caused by failure of any feed or service. The coal is conveyed by steam prior to mixing with oxygen. Flashbacks are controlled by maintaining a high steam-coal velocity. Safety hazards can occur if the steam flow drops. If oxygen is interrupted momentarily and restarted, the low inventory of coal, if flow continues, can present an explosion hazard. The gasifier is instrumented to protect against this hazard.

Gasifier Scale-Up:

The only scale up required is from the two-headed to the modular units. The scale-up ratio is about 2. Four-headed gasifiers are currently being installed in India.

Carbon Conversion:

Carbon conversion is 99%.

Overall Thermal Efficiency:

Overall thermal efficiency is 42.2%.

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.5 Koppers-Totzek (Cont'd.)

Mechanical Reliability:

The absence of moving parts makes this gasifier quite reliable. The feed screws require preventative maintenance against erosion. The refractory in a Turkish plant has been in place for 8 years. The boilers need periodic inspection as the high steam temperatures (1250°-1450°F) cause correspondingly high wall temperatures, and the large fly ash quantities can cause erosion. On-stream time in excess of 90% has been obtained, and this is fortified by the use of multiple units, which permits scheduled maintenance of individual units without shutdown of the entire facility. Quench water is sprayed into the gas to chill the fine entrained slag before it reaches the waste heat boiler tubes. This water stream prevents molten slag from depositing on the waste heat boiler tubes, resulting in fouling and corrosion.

By-Products:

Sulfur is recovered in a Stretford plant with a minimum 99% purity.

Environmental Considerations:

The facility is designed to meet established emission standards. The fly ash requires special care in disposal since it is fine (fugitive dust generation) and is high in carbon (being combustible). Landfll with rapid cover-up is the best disposal technique.

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

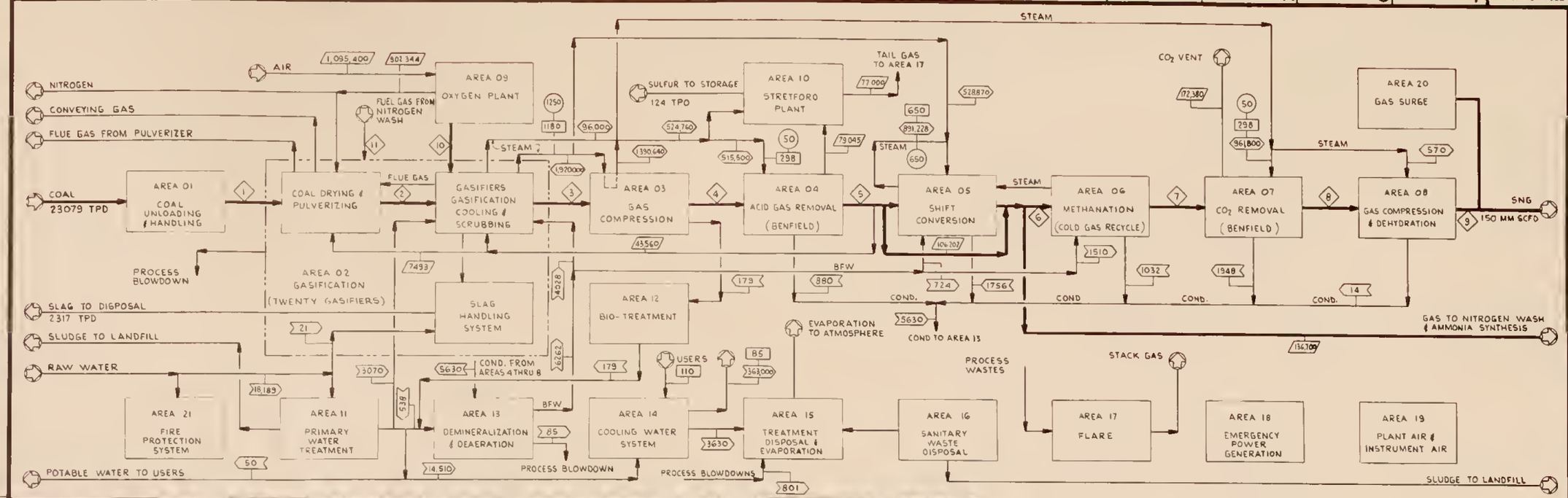
7.2.5 Koppers-Totzek (Cont'd.)

Licenses and Guarantees:

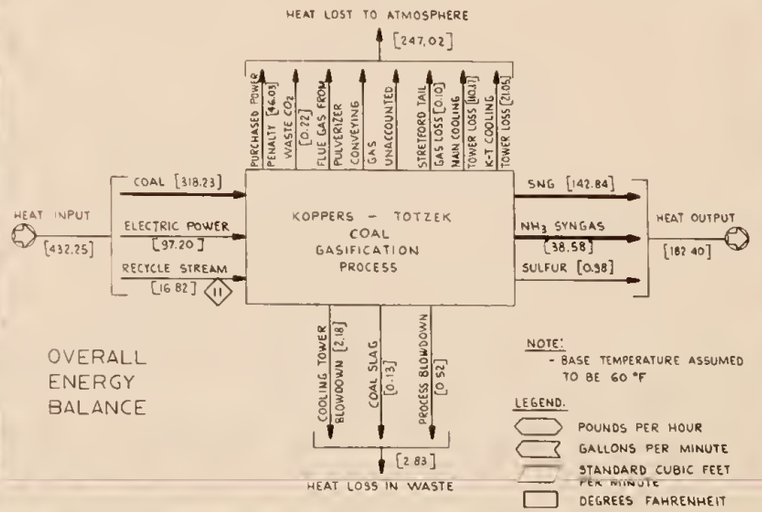
Koppers offers process guarantees on coal, oxygen and steam consumption, and product gas quality and quantity for the portion of the plant supplied by them. All license fees are on paid-up bases.

Flexibility and Turndown:

The K-T gasifier accepts all types of coal. The gasifier can be turned down to about 60% of its nominal capacity. With 20 gasifiers required for the present application, the turndown can vary over a wide range.



MATERIAL / STREAM No.	1	2	3	4	5	6	7	8	9	10	11
COMPOSITION	WT %	WT %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %
MAF COAL	58.12	82.28									
ASH	6.86	9.72									
MOISTURE	35.02	8.0									
CO			53.86	56.58	62.19	14.74	0.036	0.091	0.093		55.72
CO_2			12.32	12.93	0.01	25.03	59.31	0.58	0.53		
CH_4							35.60	90.77	52.75		
H_2			27.96	29.37	32.29	45.69	1.80	4.60	4.70		44.28
H_2S + COS			0.32	0.34	2 PPM						
N_2 + Ar			0.57	0.60	0.66	0.42	0.71	1.82	1.86	0.5	
O_2										99.5	
H_2O			4.97	0.18	4.85	14.12	2.53	2.15	0.0146		
HHV BTU/SCF(DRY)			279	279	320	228	375	952	952		323
TOTAL LB MOLES/HR			99.739	94.950	85.757	102.550	42.957	16.850	16.490	30563	7.524
TEMPERATURE °F	AMB	120	100	100	240	300	200	130	100	90	100
PRESSURE PSIG	ATM	7	5	515	500	460	440	420	1000	75	5
MM SCFD			907.23	863.67	798.24	932.79	390.74	153.27	150.00	278.00	52.07
TPD	23079	16301								11736	



OVERALL ENERGY BALANCE

$$\% \text{ O.A THERMAL EFFICIENCY} = \frac{\text{HEAT OUTPUT}}{\text{HEAT INPUT}} \times 100 = \frac{182.40}{432.25} \times 100 = 42.2\%$$

NOTE:
- BASE TEMPERATURE ASSUMED TO BE 60 °F

LEGEND.
- POUNDS PER HOUR
- GALLONS PER MINUTE
- STANDARD CUBIC FEET PER MINUTE
- DEGREES FAHRENHEIT
- PSIG
- BILLION BTU'S PER DAY

DESIGNED	ACG	8-4-76
DRAWN	DAP	8-12-76
CHECKED	RGN	10-19-76
APPROVED		
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APPROVED		

TITLE: PROCESS BLOCK FLOW DIAGRAM
K-T COAL GASIFICATION
FOR: MONTANA TRADE COMMISSION

Dravo CORPORATION
Chemical Plants Division - Pittsburgh, Pennsylvania

SCALE
DRAWING NUMBER: CPD-7024-SK-100K
REV.

REV | DESCRIPTION | MADE | CHKD | DATE
NO REV. | RELEASED FOR | APP | DATE

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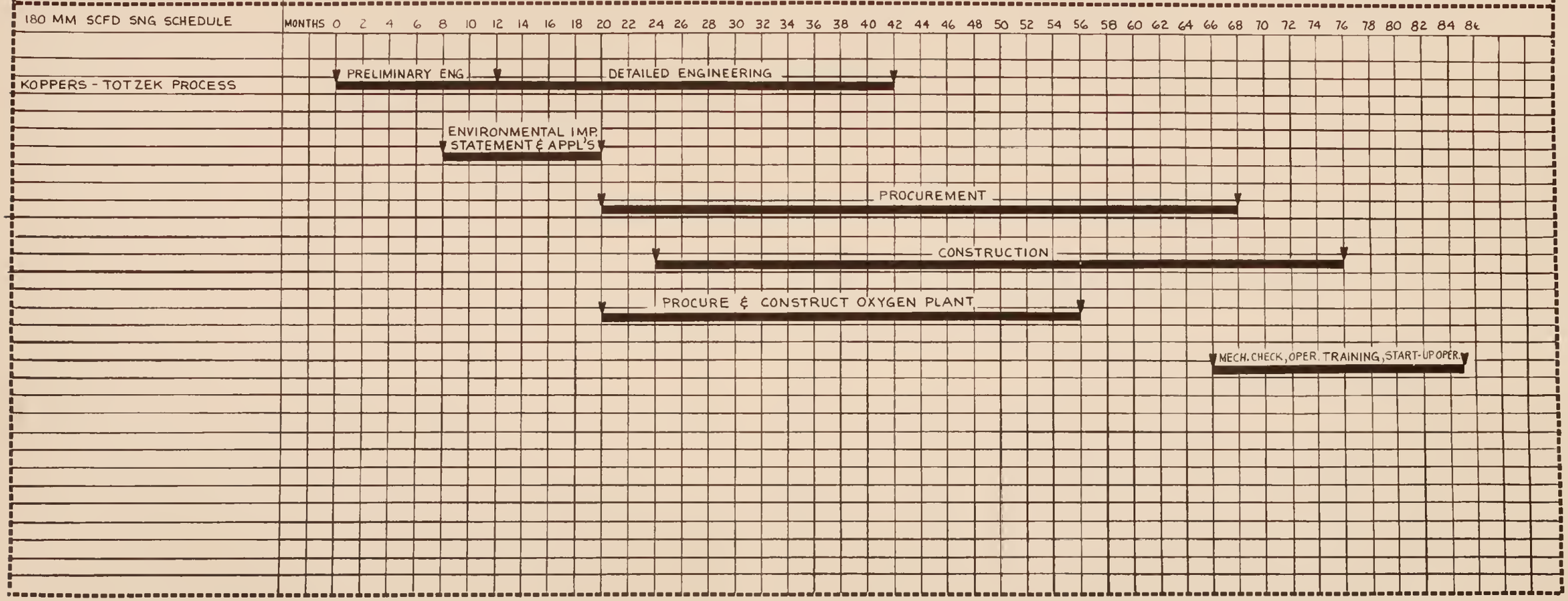
CHEMICAL PLANTS DIV.
SYNTHETIC FUELS DEPT

CPD - 7024

PROJECT SCHEDULE



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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.6 Texaco

PROCESS DESCRIPTION

The Texaco gasifier is a downflow entrained type unit of vertical, cylindrical construction. The gasifier operates at 1250 psig. Lignite-water slurry and oxygen feed streams enter at the top of the gasifier. The slag and gas formed leave at the bottom of the gasifier. Four gasifiers are needed to produce the 150 MM SCFD of SNG and the gas required for 1000 TPD of ammonia production.

The lignite feed is dried to 20 percent moisture and pulverized to 70 percent through 200 mesh. It is then slurried with water and pumped into the high pressure gasifier. Oxygen is simultaneously introduced. Gasification takes place in the upper or partial oxidation chamber of the gasifier. This section of the gasifier is refractory lined. The resulting gases and molten slag particles flow downward through a water spray chamber and a slag quench bath. This direct water cooling results in internal generation of a large quantity of high pressure steam which is partially consumed in the gasification reactions.

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.6 Texaco (Cont'd.)

The quenched slag is discharged through a slag pot located at the bottom of the gasifier. The raw gas exits the gasifier and passes through a waste heat boiler in which saturated, 1250 psig steam is generated. This partially cooled gas enters a 3-stage water scrubber where soot particles are scrubbed out and the gas is cooled to 400°F. Since the gasifier operates at 1250 psig, no additional compression is required before the gas is sent downstream for further processing.

The circulating scrubber water flows to the soot recovery system. Recovered soot is reinjected into the gasifier. Part of the clarified water is recycled to the scrubber after indirect cooling, while the balance flows to the slurry mix tank. This reduces the amount of make-up water required.

The use of a high sulfur, cobalt-moly catalyst allows CO shifting without prior removal of sulfur containing gases. This eliminates the need for cooling the gas down below 400°F before shifting. The scrubbed gas is split into two streams, with 70 percent of the gas passing through the CO shift reactors while the remainder is bypassed. These streams are recombined after shift and cooled to 100°F, by generating steam and by indirect contact with cooling water.

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.6 Texaco (Cont'd.)

The cooled gas enters a Selexol system in which essentially all of the H_2S and CO_2 are removed from the feed gas. The acid gas removed is processed in a Stretford plant to recover elemental sulfur. The purified gas exits the acid gas absorber at 100°F and 1075 psig.

A sidestream of this purified gas is transported to the liquid nitrogen wash section of the ammonia plant. A fuel gas stream is returned from the liquid nitrogen wash column to the SNG plant and is used as fuel in the coal drying area. The remaining purified gas out of the Selexol system is fed to the cold gas recycle methanator at a 3.05:1 hydrogen to carbon monoxide ratio. In the methanator, 99.9 percent of the CO in the feed gas is converted to methane. The resulting SNG is cooled for partial moisture removal and then dehydrated in a glycol dehydration unit. Compression is not required because of the high operating pressure of the gasifier. The product gas enters the product gas line at 1000 psig and 100°F. Surge bottles are provided on the product gas line to smooth out minor process upsets.

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.6 Texaco (Cont'd.)

TECHNICAL EVALUATION

Montana Lignite

The Texaco pilot plant has successfully operated on lignites from Greece and from the Lake DeSmet seam of Wyoming. No tests have been performed to date on Montana lignite, although Rosebud seam sub-bituminous coal has been processed. The entrained flow nature of the gasifier allows it to handle caking coals also. The ash fusion temperature of the lignite chosen for this study is low enough and is not expected to present any operating problem for this slagging gasifier.

Degree of Development and Technical Risk

A 100 TPD pilot plant at Morgantown, West Virginia, was operated on West Virginia coals from 1956 to 1958. Experience gained at this plant led to a number of design changes which were incorporated into the design of the present 15 TPD pilot plant in California. Tests on lignite were run in this new unit at pressures up to 1000 psig. Various bituminous coals have also been processed in this plant. A number of commercial scale Texaco gasifiers are operating on oil and tar feedstocks. The thermal efficiency of coal gasifying

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.6 Texaco (Cont'd.)

units is dependent on recycling entrained soot to the gasifier. A successful method of carrying out this operation has not yet been determined. A considerable risk is involved in scaling up to commercial size due to the large scale-up factor involved and the commercially unproven technology and the limited operating experience of the unit on solid feedstocks.

Operability and Start-Up

Texaco gasifier technology is supported by numerous units processing heavy residual oils, although actual coal gasification experience is limited to small pilot plant operations. Likely operating problems include the high pressure burners, the slurry injection system, and the external soot recycle to the gasifier.

Due to the high pressure, downfired design of the gasifier, along with the probability of the soot carryover, the start-up and operation of the unit requires careful operator attention. In addition, the slagging and soot removal steps are complicated. The process is capable of being highly automated, as demonstrated by the partial oxidation units operating on residual oils.

Gasifier Scale-Up

Scale-up risk of the reactor for this process is high due to the

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.6 Texaco (Cont'd.)

high operating pressure and the problem of distributing the down flow solid-gas mixture. Texaco recommends the use of four gasifiers to produce the required product. This represents a scale-up factor of over 400 based on lignite feed rates.

Carbon Conversion

Carbon Conversion is 97.4%.

Overall Thermal Efficiency

The overall thermal efficiency is 52.0%.

Mechanical Reliability

The soot recycle and high pressure burner operations may require considerable maintenance. The water slurry feeding system can also present problems. Some refractory erosion can be expected due to feed downflow and the slagging operation in the gasifier.

By-Products

Sulfur is recovered from acid gases in the Stretford plant at a minimum 99% purity.

Environmental Considerations

Provisions are made for the process to meet the established environmental standards. Any soot discharged to landfill creates

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.6 Texaco (Cont'd.)

a safety hazard due to its high carbon content. Landfill with rapid cover is the preferred disposal technique. Complete soot recycle would eliminate this problem.

Licenses and Guarantees

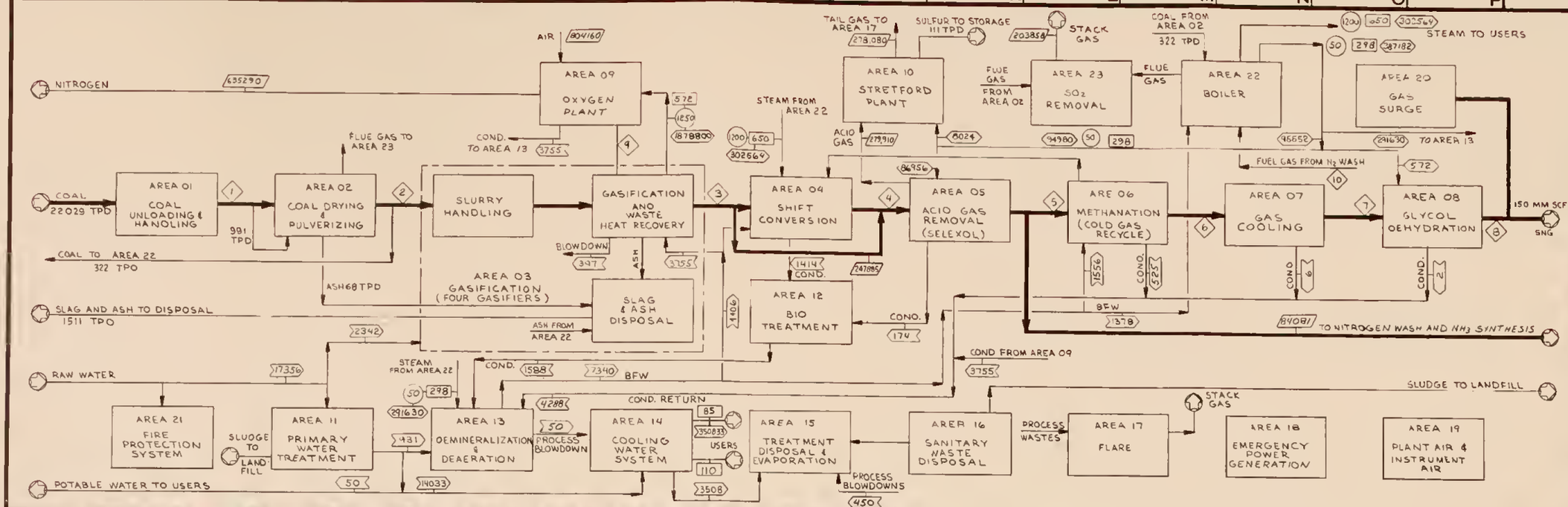
Texaco offers process guarantees for coal, steam and oxygen consumption and product gas quality and quantity. All license fees are on paid up bases.

Flexibility and Turndown

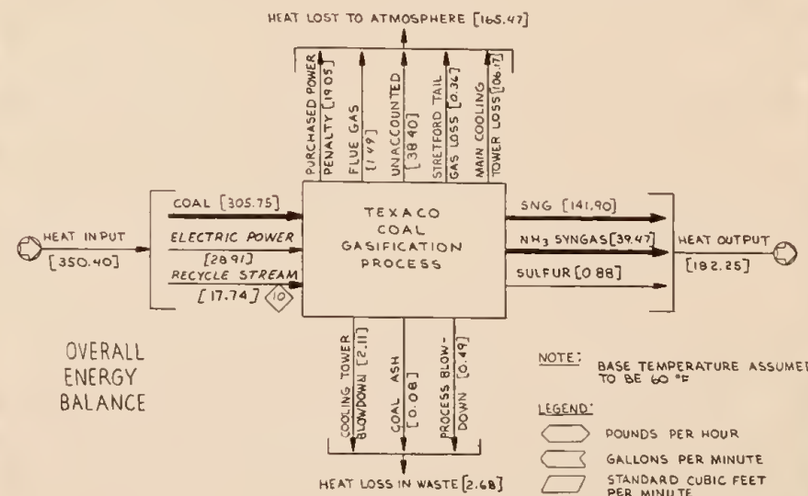
The gasifier accepts all types of coal.

Commercial experience with Texaco oil gasifiers has shown that a system turndown to 50% of design capacity is possible. It has been stated that the gasifier itself will operate satisfactorily at values as low as 15% of design capacity.[1] Since four gasifiers are used in the present application, a turndown to even lower values would be possible by shutting down some gasifiers.

(1) Child, E.T., and C. P. Marion "Recent Developments in the Texaco Synthesis Gas Generation Process", for presentation at the Fertilizer Association of Indiana, National Seminar, New Delhi, India, Dec., 1973.



MATERIAL \ STREAM No.	1	2	3	4	5	6	7	8	9	10
	WT %	WT %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %
MAF COAL	58.12	71.55								
ASH	6.86	8.45								
MOISTURE	35.02	20.00								
CO			31.18	15.50	24.35	0.08	0.08	0.09		55.31
CO_2			14.63	36.10	0.01	0.04	0.04	0.04		
CH_4			0.35	0.40	0.63	90.73	91.66	91.71		1.43
H_2			24.55	47.26	74.28	5.75	5.80	5.81		43.26
$H_2S + COS$			0.22	0.25						
$N_2 + Ar$			0.36	0.41	0.64	2.32	2.33	2.34	0.5	
O_2									99.5	
H_2O			28.71	0.08	0.09	1.08	0.09	0.01		
HHV, BTU/SCF (DRY)			257	208	326	946	946	946		333
TOTAL LB MOLES/HR			130810	116134	60589	16667	16504	16491	26869	5859
TEMPERATURE, °F	AMB	150	403	100	100	200	100	100	250	100
PRESSURE, PSIG	ATM	ATM	1145	1105	1075	1055	1000	1000	1250	5
MMSCFD								150		53.29
TPD	22029	16390							10318	



OVERALL ENERGY BALANCE

NOTE: BASE TEMPERATURE ASSUMED TO BE 60 °F

LEGEND:
- POUNDS PER HOUR
- GALLONS PER MINUTE
- STANDARD CUBIC FEET PER MINUTE
- DEGREES FAHRENHEIT
- PSIG
- [ ] BILLION BTU'S PER DAY

$$\% \text{ O.A. THERMAL EFFICIENCY} = \frac{\text{HEAT OUTPUT}}{\text{HEAT INPUT}} \times 100 = \frac{182.25}{350.40} \times 100 = 52.0\%$$

DESIGNED	ACG	8-30-76
DRAWN	MC PAT	9-14-76
CHECKED	RGN	10-19-76
APPROVED		
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TITLE: PROCESS BLOCK FLOW DIAGRAM
TEXACO COAL GASIFICATION

FOR: MONTANA TRADE COMMISSION

Dravo CORPORATION
Chemical Plants Division • Pittsburgh, Pennsylvania

SCALE: —//—

DRAWING NUMBER: CPD-7024-SK-100T

REV.

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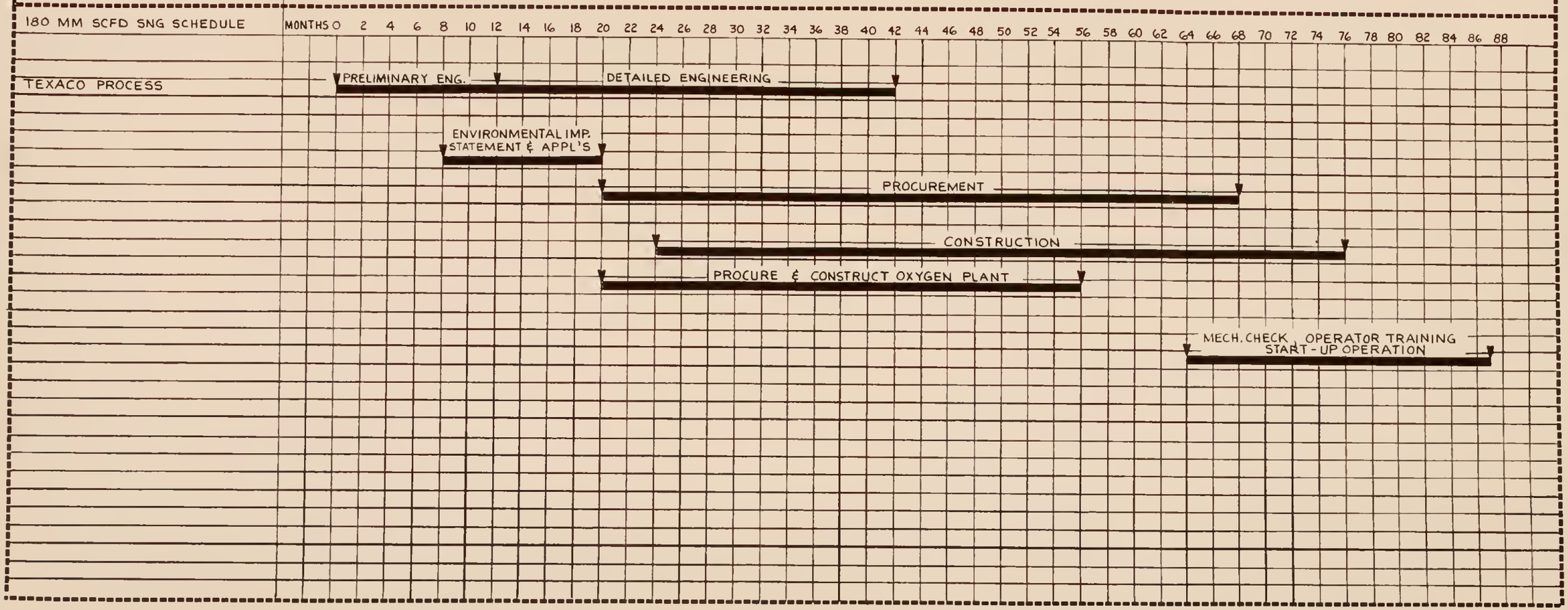
CHEMICAL PLANTS DIV
SYNTHETIC FUELS DEPT.

CPD - 7024

PROJECT SCHEDULE



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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.7 Winkler

PROCESS DESCRIPTION

The Winkler fluid bed gasifier is a refractory lined cylindrical vessel designed to gasify coal at above atmospheric pressures (~30 psig). The coal feed is injected into the bottom of the gasifier. Saturated low pressure steam and oxygen are fed through nozzles located at several levels in the fluid bed. The fluidized bed occupies only part of the gasifier volume, while the remainder serves as a disengaging zone. Secondary steam and oxygen above the bed level gasify unconverted carbon suspended above the bed. Above this level, a radiant heat boiler is installed to recover heat from the gases before they leave the gasifier and to resolidify any solid particles which may have melted. Twelve gasifiers with 16 ft. I.D. are needed to produce the 150 MMSCFD of SNG and the gas required for 1000 TPD of ammonia production.

The lignite feed is reclaimed from storage and dried from 35% to 8% moisture. It is then crushed from minus 2 inch size to minus 3/8 inch. The processed lignite is transported to feed bunkers provided with each gasifier. A variable speed screw feeds the lignite into the gasifier. This screw also serves as a seal to

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.7 Winkler (Cont'd.)

prevent steam in the gasifier from wetting the lignite in the bunker.

The raw product gas leaving the gasifier passes through a heat recovery train in which superheated steam is generated, boiler feed water and the oxygen to the gasifier are preheated, and the majority of the fly ash with a percentage of unconverted carbon (henceforth referred to as char) is removed in a cyclone. The char collected is combined with the gasifier bottom char and sent to the boiler where a coal-char mixture is burned to generate steam. The raw gas leaving the cyclone is further cooled and scrubbed in a scrubbing cooler.

The cool, clean gas is compressed to 515 psig. This gas enters a Benfield acid gas removal system where essentially all of the H_2S and CO_2 are removed. The acid gas stream is fed to a Stretford plant where elemental sulfur is recovered as a by-product.

The purified gas stream exiting the acid gas adsorber at 240°F is heated by the CO shift product gas. It then enters a zinc oxide adsorber where residual trace amounts of sulfur compounds are removed. The gas stream is then split, 70% of the gas passing through CO shift, while the remainder bypasses it. These two

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.7 Winkler (Cont'd.)

streams are recombined after shift. A sidestream taken off as the feed to the ammonia plant, and the remaining gas is fed to methanation at 460 psig and 300°F. A fuel gas stream is recycled from the nitrogen wash column to the coal crushing and drying section. It supplements the lignite in providing the heat for drying.

In the cold gas recycle methanation unit, 99.9 percent of the carbon monoxide in the feed gas is converted to methane. This raw SNG is passed through another Benfield system where the CO_2 formed in CO-shift is removed. The CO_2 is vented to the atmosphere. The purified SNG is dehydrated in a glycol dehydration unit and compressed to 1000 psig. Surge bottles are provided on the product gas line to smooth out minor process.

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.7 Winkler (Cont'd.)

TECHNICAL EVALUATION

Montana Lignite

Although the Winkler gasifier has not operated on Montana lignite, two commercial facilities, one in India and one in Turkey, are presently operating with a lignite feedstock. Numerous commercial plants which are no longer on stream also processed lignite. No commercial Winkler units have been constructed in the United States to date. American HVCB coal has been tested in a full scale gasifier in Germany.

Degree of Development and Technical Risk

Initial development work was completed in the early 1920's. The first commercial plant was put into operation at Leuna, Germany, in 1926. Since then, 16 commercial plants have been installed in European and Asian countries. Both air and oxygen have been used as the gasification medium. The gasifier, as it is proposed to be used in the present application, can be considered a commercially proven gasifier. The gasifier was operated at near atmospheric pressures in the past. The proposed gasifier operates at 30 psig. Since the original screw feeding mechanism is used even at this pressure, it represents some risk in adapting the older design for the higher pressure.

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.7 Winkler (Cont'd.)

Operability and Start-Up

Due to the experience gained from the commercial plants already placed in operation, a minimum amount of operative and start-up problems are expected. The screw feeding mechanism of the low pressure gasifier however may cause problems in the high pressure operation.

Gasifier Scale-up

No reactor scale-up is required since multiples of modular units are used. Commercial units have been constructed with diameters ranging from 3 to 18 feet. Twelve gasifiers with 16 feet I.D. are recommended for this application.

Carbon Conversion

88.1%

Overall Thermal Efficiency

50.8%

Mechanical Reliability

The lignite feed and ash removal screw mechanisms require preventive maintenance against erosion. The high ash carry-over rate may cause

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.7 Winkler (Cont'd.)

problems in the operation of the raw product gas compressor and excessive erosion of refractories. Proper functioning of the waste heat boiler is necessary to prevent deposition of molten ash in the firing space from depositing in the exit duct. However, the extensive amount of commercial operating experience combined a scheduled maintenance program should result in a reliable installation.

By-Products

Sulfur is recovered in a Stretford plant at a minimum 99% purity.

Environmental Considerations

The facility is designed to meet established emission standards. The char produced is burned in the boiler along with coal. The flue gas from the boiler is scrubbed to reduce the SO_2 content down to 1.2 lb/MM Btu, before its discharge to atmosphere.

Licenses and Guarantees

Davy Powergas, Inc., (Licensors for Winkler in U.S.) guarantee would be negotiable based upon a complete design analysis and requirements. All license fees are on a royalty basis to the end user.

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

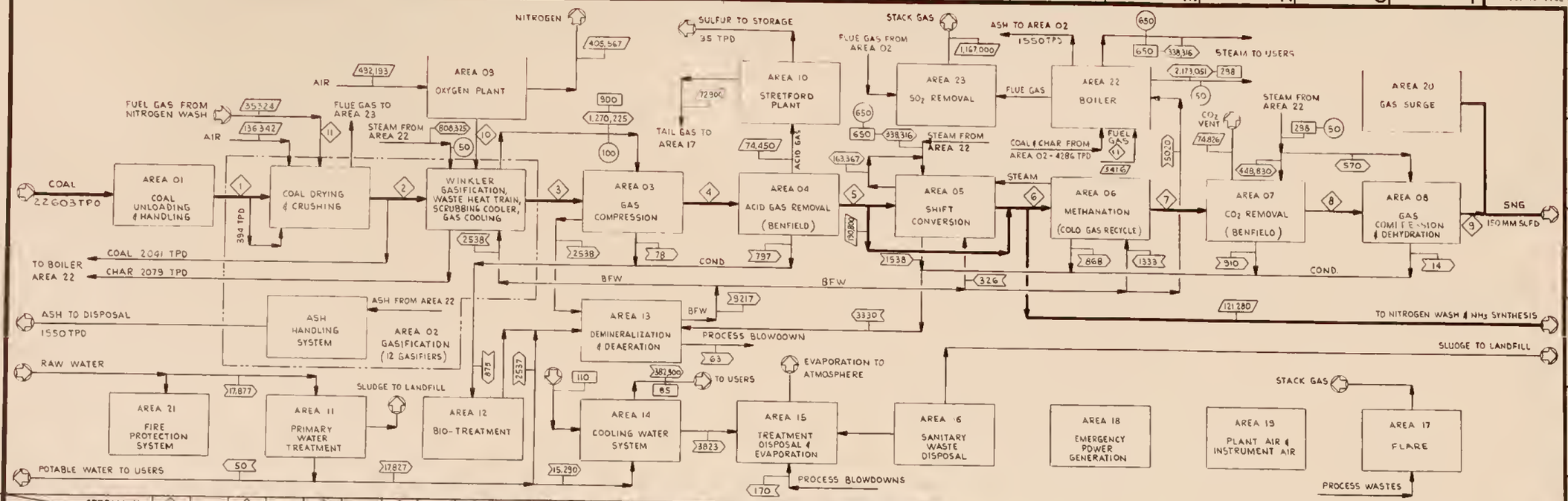
7.2 Description and Technical Evaluation (Cont'd.)

7.2.7 Winkler (Cont'd.)

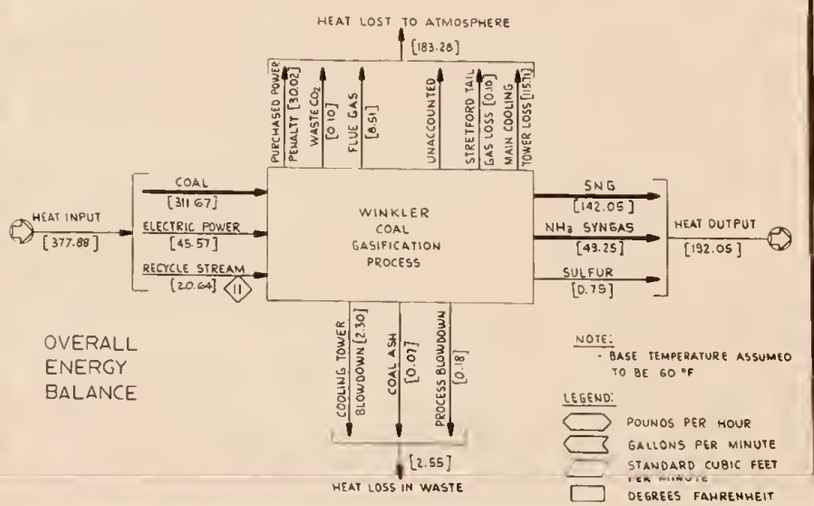
Flexibility and Turndown

The gasifier has been operated mainly with lignite and sub-bituminous type coals. A test program for U. S. bituminous coals is underway. It is expected that bituminous coals with free swelling indices less than four would be acceptable as feed coals; coals with free swelling indices higher than four may require pretreatment.

Turndown of the gasifier will be limited by the minimum gas flow required for fluidization. Expected turndown for each gasifier is 25%. With twelve gasifiers required for the present application, the turndown can vary over a wide range.



MATERIAL / STREAM No.	1	2	3	4	5	6	7	8	9	10	11
COMPOSITION	WT %	WT %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %	MOL %
MAF COAL	58.12	82.28									
ASH	6.86	9.72									
MOISTURE	35.02	8.00									
CO			37.17	38.15	42.43	16.61	0.05	0.08	0.08		52.00
CO_2			13.62	13.98	0.01	15.00	40.91	0.28	0.28		
CH_4			2.53	2.59	2.88	2.15	52.42	30.44	32.40		6.73
H_2			42.91	44.04	48.98	51.48	2.35	4.06	4.17		41.27
$H_2S + COS$			0.23	0.30	2 PPM						
$N_2 + Ar$			0.74	0.76	0.84	0.64	1.73	2.99	3.06	0.5	
O_2										99.5	
H_2O			2.74	0.18	4.85	14.12	2.54	2.15	0.0147		
HHV, BTU/SCF (DRY)			295	295	341	282	551	947	947		
TOTAL LB MOLS/HR			84757	82588	74252	80463	29071	16851	16491	13,714	369
TEMPERATURE, °F	AMB	150	100	100	240	300	200	130	100	90	6133
PRESSURE, PSIG	ATM	ATM	20	515	500	460	440	420	1000	75	100
MM SCFD			771.0	751.2	675.4	731.9	264.4	153.3	150.0	124.7	5
TPD	22603	13857									55.78



OVERALL ENERGY BALANCE

$$\% \text{ O.A. THERMAL EFFICIENCY} = \frac{\text{HEAT OUTPUT}}{\text{HEAT INPUT}} \times 100 = \frac{192.05}{377.88} \times 100 = 50.8\%$$

NOTE:
- BASE TEMPERATURE ASSUMED TO BE 60 °F

LEGEND:
- POUNDS PER HOUR
- GALLONS PER MINUTE
- STANDARD CUBIC FEET PER MINUTE
- DEGREES FAHRENHEIT
- PSIG
- [ ] BILLION BTU'S PER DAY

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DRAWN	DAP	8-25-76
CHECKED	RGN	10-19-76
APPROVED		
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PROCESS BLOCK FLOW DIAGRAM
WINKLER PROCESS
COAL GASIFICATION

FOR MONTANA TRADE COMMISSION

Dravo CORPORATION
Chemical Plants Division · Pittsburgh, Pennsylvania

SCALE

DRAWING NUMBER CPD-7024-SK-100W

REV.

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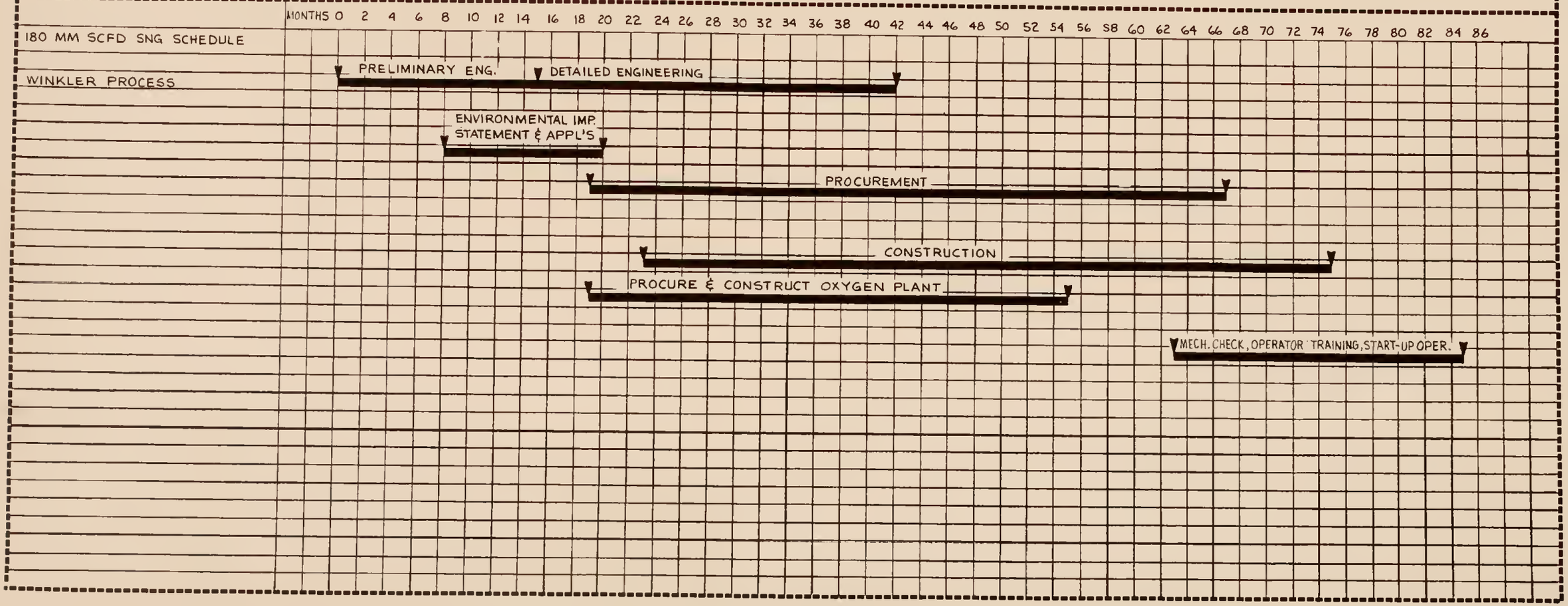
PROJECT SCHEDULE



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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.8 Lurgi

PROCESS DESCRIPTION

The Lurgi fixed bed gasifier is a double shell pressure vessel operating at about 425 psig. Gasification reactions take place within the inner shell, which is cooled by generation of steam in the annular water jacket between the two shells. This steam, combined with externally produced superheated steam, is mixed with the required amount of oxygen, and injected into the bottom of the gasifier below the ash grate. This steam-oxygen mixture is heated by direct contact with hot ash leaving the grate. Properly sized lignite is fed through the top of the gasifier by means of a pressurized hopper. Twenty gasifiers, eighteen operating and two spares, are required to produce the 150 MM SCFD of SNG and the gas needed to produce the required for 1000 TPD of ammonia production.

Graded coal is fed into the coal bunkers located at the top of the gasifiers. From here, the coal is charged into the gasifiers through automatically operated coal locks. Superheated steam and oxygen are injected through the ash grate. The raw crude gas formed in the gasifier is washed and water quenched immediately after exiting the gasifier. This wash removes coal dust entrained in the gas and also condenses some of the heavy tars produced in

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.8 Lurgi (Cont'd.)

the gasifier. The two phase mixture passes through a waste heat boiler in which it is cooled to 367°F by generating 85 psig saturated steam.

The raw product gas then flows to the shift conversion waste heat boiler in which it is further cooled prior to entering the shift reactors. Condensate from this boiler and from the gasifier waste heat boiler is transferred to the gas liquor product separation section of the plant.

Approximately 58% of the CO shift area feed gas enters the shift reactors while the remainder is bypassed. The two streams are recombined after the shift step and split again into SNG and ammonia production feedstreams. These two streams are cooled in separate gas-cooling units by generating 55 psig and 15 psig saturated steam, respectively. Further cooling is accomplished by preheating boiler feedwater and finally by exchange with cooling water. All tars and oils condensed out are sent to the gas liquor separation unit for recovery as by-products.

The effluent from the gas liquor separation unit is pumped to the Phenosolvan plant for phenol extraction. The liquor leaving phenol

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.8 Lurgi (Cont'd.)

recovery enters a Chemie-Lurgi-Linz process in which anhydrous ammonia is recovered. After recovery of these by-products, the remaining gas liquor stream can be treated in a biotreatment plant to produce an environmentally acceptable effluent.

The cooled gas is now treated in two separate, three absorption cycle, Rectisol systems. In the first cycle, gas naphtha and water are removed by washing with a small quantity of methanol, the Rectisol solvent. The second cycle is designed to remove the bulk of the hydrogen sulfide and organic sulfur compounds from the gas. The third cycle removes the bulk of the carbon dioxide. The methanol streams are regenerated to remove the absorbed products. The naphtha is decanted and sent to by-product storage, while the acid gases flow to the sulfur recovery area of the plant.

The purified gas to ammonia production is treated in another Rectisol unit in which any CO_2 left in the gas is removed. The CO_2 free gas enters the liquid N_2 wash and is split into three streams - the ammonia synthesis gas, a fuel gas stream which can be used in another part of the plant, and a methane-rich stream which is recycled to the methanator inlet. This last stream is combined with the purified gas to SNG production and the entire stream is passed through the methanator, where 99.8 percent of the feed CO is converted to methane.

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.8 Lurgi (Cont'd.)

The resulting SNG is then compressed and enters the product gas line at 1000 psig and 100°F. Surge bottles are provided on the product gas line to smooth out minor process upsets.

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.8 Lurgi (Cont'd.)

TECHNICAL EVALUATION

Montana Lignite

The Lurgi gasifier has been successfully operated in a commercial unit on a North Dakota lignite having properties similar to those of the Montana lignite. Sub-bituminous coal from Montana's Rosebud seam and Illinois Nos.5 and 6 and Pittsburgh No.8 bituminous coals have also been processed in Lurgi units.

Degree of Development and Technical Risk

The gasifier has been demonstrated in plants in Europe and Africa. Currently, installations are being designed and constructed for SASOL, South Africa; Germany; and Chicago, Illinois. The unit is commercialized to the point where its selection involves minimal risk.

Operability and Start-Up

The experience of the commercial units on stream offers a high degree of operating expertise. The dry ash discharge eliminates the freezing problems of slagging units.

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.8 Lurgi (Cont'd.)

The by-product operations involve typical chemical processes. Systems such as Phenosolvan and tar-oil separation are coordinated with the operation of the main plant by installing liquid surge capacity.

No unusual start-up problems are envisioned because of the number of commercial plants on stream to date.

Gasifier Scale-Up

No gasifier scale-up is required since multiples of commercial modular units are used.

Carbon Conversion

99.2%

Overall Thermal Efficiency

60.1%

Overall thermal efficiency values used in this report were based on the coal equivalent of 10,000 BTU/KWH for purchased power instead of the heat equivalent of 3413 BTU/KWH used in the Lummus report. The Lummus overall thermal efficiency was adjusted accordingly.

Mechanical Reliability

The Lurgi plants have a high availability, when supplemented by a scheduled maintenance program, for the coal and ash lock hopper valves

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.2 Description and Technical Evaluation (Cont'd.)

7.2.8 Lurgi (Cont'd.)

and other moving parts. Such scheduled maintenance allows the individual gasifiers to achieve an availability in excess of 90%.

By-Products

The Lurgi facility produces a number of by-products, including tar, oil, crude phenols, and naphtha which contain some sulfur. At the SASOL plant in South Africa their utility for further chemical processing is not affected by the sulfur content. They may be used as a fuel combined with stack gas cleaning. Sulfur and anhydrous ammonia are generated as salable by-products.

Environmental Considerations

The plant is designed for compliance with established emission regulations, and no special problems remain for disposal of ash and sludge.

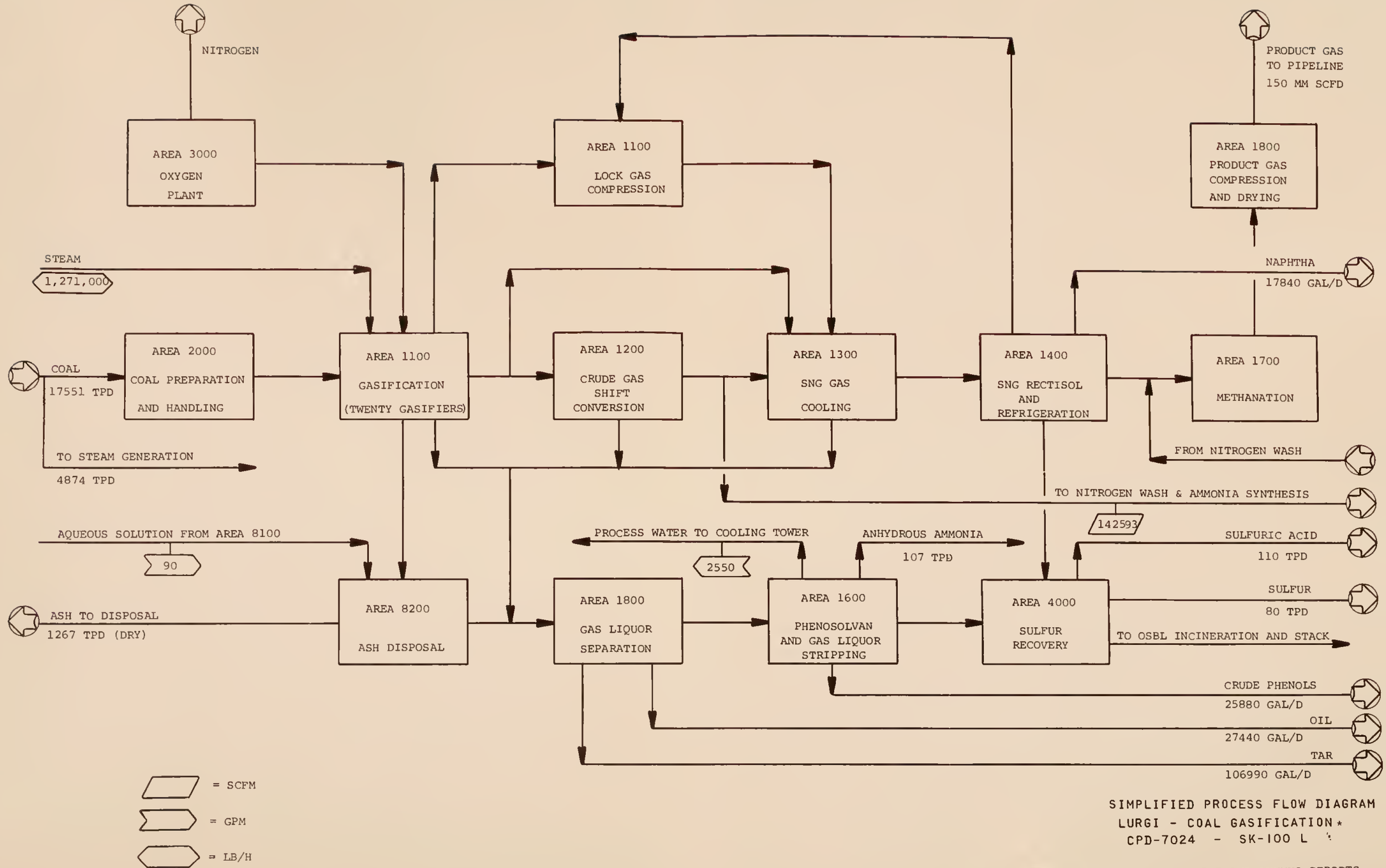
Licenses and Guarantees

Lurgi offers process guarantees on coal, oxygen and steam consumption, and gas quality and quantity. All license fees are on paid up bases.

Flexibility and Turndown

The gasifier accepts caking and non-caking coals. It has been observed that use of caking coals slightly reduces the gasifier throughput and increases the steam requirements.

Expected turndown for each gasifier is 25%. With 20 gasifiers required for the present application, the turndown can vary over a wide range.



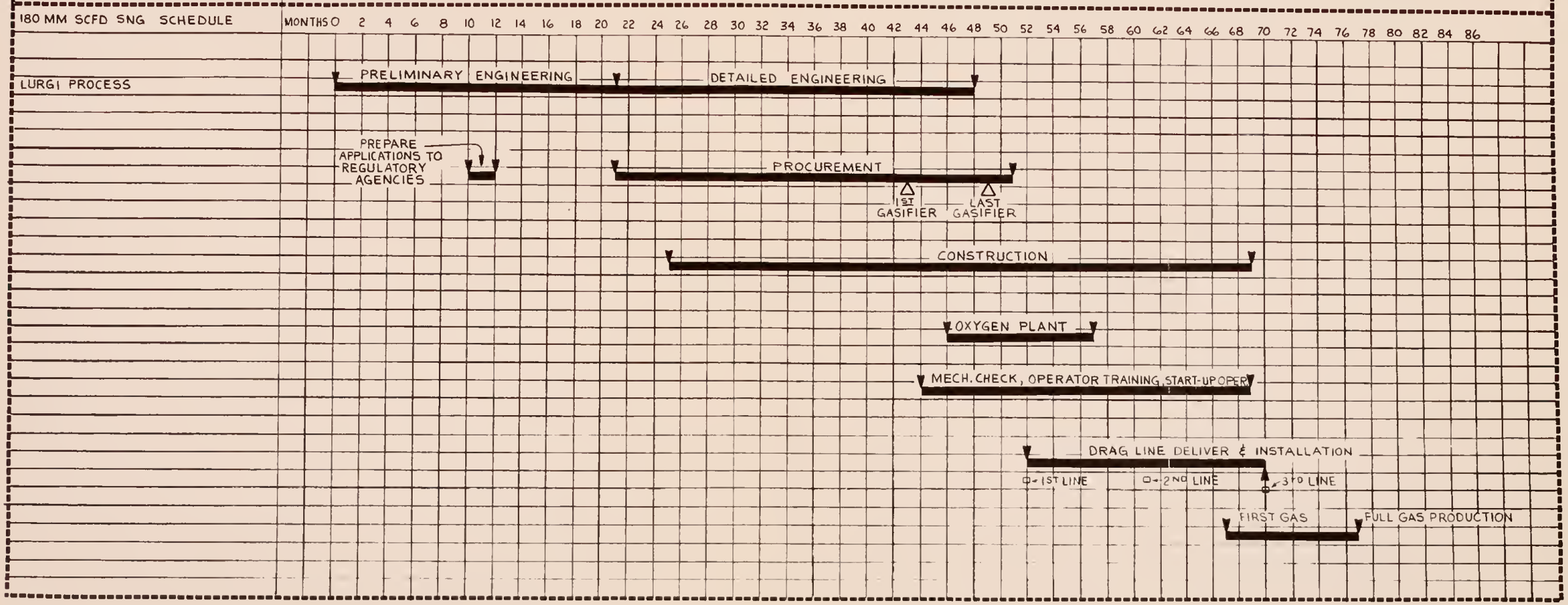
SIMPLIFIED PROCESS FLOW DIAGRAM
LURGI - COAL GASIFICATION*
CPD-7024 - SK-100 L

*BASED ON THE LURGI AND LUMMUS REPORTS

CPD - 7024

PROJECT SCHEDULE

BASED ON THE LUMMUS COMPANY REPORT TO
MONTANA TRADE COMMISSION



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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.3 Summary of Technical Evaluation

The attached table represents the summary of technical evaluations of the processes under consideration. The rating points assigned to each process reflect the qualitative judgements of the process with respect to the criteria.

The following is a discussion of the bases of the point ratings. The attributes and tests for each criterion for which the processes are examined are listed followed by a short discussion of each process and the point ratings assigned.

Montana Lignite Coal (Top Rating = 10)

- Demonstrated capability to handle Montana lignite, i.e., the process is run on Montana lignite for extended periods with reproducible data.
- Demonstrated capability to handle other lignite coals
- Flexibility to process various types of coals

Assignment of Point Ratings

		POINT RATINGS
B&W:	The gasifier has been operated on lignite from the Lake DeSmet area of Wyoming.	6

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.3 Summary of Technical Evaluation (Cont'd.)

Montana Lignite Coal (Top Rating = 10) (Cont'd.)

		POINT RATINGS
CO_2 Acceptor:	The CO_2 Acceptor pilot plant has been run mostly on lignites. Montana lignite has not been processed.	8
COGAS:	Pyrolysis unit has been operated on lignite. Char from lignite gasified only on bench scale.	7
HYGAS:	The HYGAS pilot plant has been run mostly on lignites.	8
K-T:	All commercial installations of the K-T gasifier, with one exception, have been operated on lignite. Montana lignite has not been processed.	10
Texaco:	The Texaco pilot plant has been operated on lignites from Greece and the Lake DeSmet area of Wyoming.	6
Winkler:	Many commercial Winkler gasifiers have operated on lignites, with two currently	10

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.3 Summary of Technical Evaluation (Cont'd.)

Montana Lignite Coal (Top Rating = 10) (Cont'd.)

		POINT RATINGS
Winkler: (Cont'd.)	in operation. Montana lignite has not been processed.	
Lurgi:	The Lurgi gasifier has been successfully operated in a commercial unit on a North Dakota lignite having properties similar to those of the Montana lignite.	10

Degree of Development and Technical Risk (Top Rating = 20)

- Process is commercially proven
- Currently running pilot plant which was operated on Montana lignite or similar coal and is capable of operating on the Montana lignite coal for the purpose of gathering definitive design data.
- Pilot plant data are available as a back-up for the material and energy balance.
- Credibility of pilot plant data and identification of problems involved in obtaining the data.
- Extension of new technology

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.3 Summary of Technical Evaluation (Cont'd.)

Degree of Development and Technical Risk (Top Rating = 20) (Cont'd.)

- Lengths of pilot plant runs, feed rate, types of coal, and operating conditions.

Assignment of Point Ratings		POINT RATINGS
B&W:	A 400 TPD semi-commercial plant operated in the late 1950's. Another 12 TPD unit was operated up to 300 psig of pressure. The B&W gasifier uses current technology used in such commercial units as the waterwall boiler, the coal fed blast furnace, and the cyclone furnace.	14
CO_2 Acceptor:	A 30 TPD Pilot Plant has been run on lignite at 150 psig. Runs up to 12 days long have been completed with an integrated gasifier-regenerator operation. The pilot plant is available for further data gathering.	12

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.3 Summary of Technical Evaluation (Cont'd.)

Degree of Development and Technical Risk (Top Rating = 20) (Cont'd.)

		POINT RATINGS
COGAS:	Tests on pilot plant scale with several American coals indicate no major problems. Integrated operation of pyrolysis with gasification has not been demonstrated. The pilot plant is available for further data gathering.	12
HYGAS:	The 75 TPD Pilot Plant has been run on lignite up to 1000 psig. A 15-day self-sustained run was achieved with Montana lignite during June and July, 1975. The pilot plant is available for further data gathering.	12
K-T:	Process is commercially proven.	20
Texaco:	The gasifier is commercially proven for using liquid and gaseous hydrocarbon as feedstocks. A 15 TPD pilot plant is currently operating and has been operated on coals. Soot	12

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.3 Summary of Technical Evaluation (Cont'd.)

Degree of Development and Technical Risk (Top Rating = 20) (Cont'd.)

		POINT RATINGS
Texaco: (Cont'd.)	recycle portion of the gasifier has not been tested. The pilot plant is available for further data gathering.	
Winkler:	Process is commercially proven on lignite coals at near atmospheric pressures. Operation of the gasifier at 30 psig may present some problems, especially in the screw feeding injection mechanism.	16
Lurgi:	The process is commercially proven.	20

Operability and Start-UP (Top Rating = 10)

- The gasifier system or parts thereof are operated with replicate results.
- Ease of operation and start-up
- Length of self-sustained operation
- Automation capability
- Similarity to known technology

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.3 Summary of Technical Evaluation (Cont'd.)

Operability and Start-Up (Top Rating = 10) (Cont'd.)

- Number of operations not demonstrated
- Problems indigenous to the process
- Probability of unsafe conditions

Assignment of Point Ratings		POINT RATINGS
B&W:	Experience in the 400 TPD semi-commercial and pulverized coal boiler operations supports and operability. Module size operations at pressure and the char recycle technique must be demonstrated.	7
CO_2 Acceptor:	Integrated pilot plant runs with lignite coals yielding reproducible results support operability on a small scale. Commercial scale has not been demonstrated.	7

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.3 Summary of Technical Evaluation (Cont'd.)

Operability and Start-Up (Top Rating = 10) (Cont'd.)

		POINT RATINGS
COGAS:	The pyrolyzers and char gasifier have been run separately with reproducible results. Integrated operation has to be demonstrated. The fluid beds and the high pressure hydrodesulfurizer need careful attention during start-up and shutdown. The oil de-ashing and solids circulation systems may present some problems.	6
HYGAS:	Reactor design complexity, coal slurry feed system, internal solids circulation, and internal steam-oxygen gasification of char may present operational problems. The high pressure operation adds to the problems.	6

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.3 Summary of Technical Evaluation (Cont'd.)

Operability and Start-Up (Top Rating = 10) (Cont'd.)

		POINT RATINGS
K-T:	Extensive commercial operation experience. Fly ash overhead and deposition of carry-over molten slag on the waste heat boiler tubes present operation problems.	9
Texaco:	Soot recycle has not been demonstrated. Oil units are running, but coal work has been limited to pilot scale units. High operating pressure may present problems with burner function and coal distribution.	6
Winkler:	The high pressure (~30 psig) operation and the radiant waste heat boiler inside the gasifier is a new development and may present problems. Fly ash overhead may also present operation problems.	8

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.3 Summary of Technical Evaluation (Cont'd.)

Operability and Start-Up (Top Rating = 10) (Cont'd.)

		POINT RATINGS
Lurgi:	Experience from the commercial units currently on stream offers a high degree of operating expertise.	9

Gasifier Scale-Up (Top Rating = 20)

- o Gasifier size for Pilot Plant vs. the size used for this study.
- o Number of trains
- o Safe scale-up factor

Assignment of Point Ratings		POINT RATINGS
B&W:	Scale-up factor is 9 and is within safe limits of scale-up. Number of gasifiers = 4	16
CO_2 Acceptor:	Scale-up factor assumed for this study is over 250 and represents a high risk factor. Number of trains = 2	8

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.3 Summary of Technical Evaluation (Cont'd.)

Gasifier Scale-Up (Top Rating = 20) (Cont'd.)

		POINT RATINGS
COGAS:	Scale-up factors are 300 for pyrolysis and 120 for gasification and represent high risk factors. Number of trains = 2	8
HYGAS:	Scale-up factor is over 80, and this, coupled with intricate gasifier internals, makes it a high risk scale-up. Number of gasifiers = 2	10
K-T:	Scale-up factor is about 2, from the commercially proven two-headed gasifier to the four-headed gasifier proposed for this plant. Four-headed gasifiers are currently being installed in India. Number of gasifiers = 2	18
Texaco:	Scale-up factor of over 400 combined with high pressure operation represent a high risk factor. Number of gasifiers = 4	8

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.3 Summary of Technical Evaluation (Cont'd.)

Gasifier Scale-Up (Top Rating = 20) (Cont'd.)

		POINT RATINGS
Winkler:	No scale-up involved. Multiple modules of commercially proven units are used to meet rated plant capacity. Number of gasifiers = 12	20
Lurgi:	No scale-up involved. Multiple modules of commercially proven units are used to meet rated plant capacity. Number of gasifiers = 20	20

Mechanical Reliability (Top Rating = 10)

- Problems of erosion and corrosion
- Problems encountered on pilot unit
- Solids handling and recycle
- Number of units
- Impact of gasifier shutdown

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.3 Summary of Technical Evaluation (Cont'd.)

Mechanical Reliability (Top Rating = 10) (Cont'd.)

Assignment of Point Ratings		POINT RATINGS
B&W:	Overhead solids recycling in pressure gasifier requires demonstration.	7
CO_2 Acceptor:	High rate recycling of the hot acceptor may cause erosion problems. A reliable method for power recovery by means of gas turbines from the dust-laden hot regeneration gas must be established. The refractory used in the pilot plant gasifier and regenerator has satisfactorily withstood thermal cycling.	5
COGAS:	Large quantities of hot circulating char creates erosion problems. Multiplicity of components involved per unit train may create interaction problems.	5

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.3 Summary of Technical Evaluation (Cont'd.)

Mechanical Reliability (Top Rating = 10) (Cont'd.)

		POINT RATINGS
HYGAS:	The slurry feeding system, internal solids transfer, and high pressure operating environment may present problems.	5
K-T:	Coal feed screws require frequent preventive maintenance. High fly ash content in the gas can cause erosion, corrosion problems.	9
Texaco:	High pressure burner operation, slurry feeding system and soot recycle may present problems.	5
Winkler:	Coal feed and ash withdrawal screws require frequent preventive maintenance. The radiant heat recovery boiler in the gasifier is a new development and may cause erosion and corrosion problems.	7

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.3 Summary of Technical Evaluation (Cont'd.)

Mechanical Reliability (Top Rating = 10) (Cont'd.)

		POINT RATINGS
Lurgi:	The Lurgi plants have a high availability. Scheduled maintenance is required for gasifier internal moving parts, and coal and ash lock hopper valves.	9

By-Products (Top Rating = 5)

The quality of the by-products, and potential environmental problems associated with the by-products are evaluated. A process with a valuable by-product or with no other by-product than sulfur is scored high.

The ash produced in the HYGAS and Winkler gasifiers contains over 20% unconverted carbon and is a potential fire hazard. The ash must be covered with soil at the landfill. In the K-T process, about one half of the incoming ash in the coal is entrained in the product gas leaving the gasifier. This ash has to be removed by scrubbing before the gas is sent for further processing.

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.3 Summary of Technical Evaluation (Cont'd.)

By-Products (Top Rating = 5) (Cont'd.)

Only COGAS, HYGAS and Lurgi produce liquid hydrocarbons by-products. The hydrocarbons produced in COGAS and HYGAS processes, as described in this report, are clean, valuable by-products. Lurgi produces some oils, tars and phenols containing some sulfur. They can be utilized as a fuel combined with stack gas cleaning.

The processes and point ratings are listed below:

PROCESS	POINT RATINGS
B&W	5
CO_2 Acceptor	5
COGAS	5
HYGAS	4
K-T	4
Texaco	5
Winkler	4
Lurgi	4

PROCESS SELECTION STUDY
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FOR
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TECHNICAL EVALUATION RATINGS

EVALUATION CRITERIA	B&W	CO_2 ACCEPTOR	COGAS	HYGAS	K-T	TEXACO	WINKLER	LURGI	TOP RATING
MONTANA LIGNITE COAL	6	8	7	8	10	6	10	10	10
DEGREE OF DEVELOPMENT & TECHNICAL RISK	14	12	12	12	20	12	16	20	20
OPERABILITY & START-UP	7	7	6	6	9	6	8	9	10
GASIFIER SCALE-UP	16	8	8	10	18	8	20	20	20
MECHANICAL RELIABILITY	7	5	5	5	9	5	7	9	10
BY-PRODUCTS	5	5	5	4	4	5	4	4	5
TOTALS	55	45	43	45	70	42	65	72	75

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.4 Cost Estimates

Capital Cost

Capital cost estimates were developed by Dravo for all the processes except Lurgi. The capital cost estimate for the Lurgi process was developed by Lummus. The capital cost and the gas cost estimates are presented in this Subsection. All costs are expressed in August, 1976 dollars.

The cost estimates prepared by Lummus for the Lurgi process were examined by Dravo for consistency of bases. The Lummus estimate for the Lurgi process included the cost of Syngas Treatment facilities for the manufacture of ammonia. The estimates of the other processes did not include the treatment facilities. For consistency, therefore, the costs of these areas were deleted from the Lummus estimate. These facilities included: ammonia gas cooling, ammonia Rectisol and refrigeration, final CO_2 wash (Rectisol) and refrigeration, N_2 compression and liquid N_2 wash and the ammonia synthesis loop. Also, the cost of water, utilities and other peripheral areas including site development, buildings and interconnecting piping were scaled down in direct proportion.

The costs of the gasification and raw gas quench areas of the HYGAS process, and the costs of the coal preparation, gasification, and raw gas quench areas of the B & W and Texaco processes were based on estimates by the respective process licensors. For the CO_2 Acceptor process,

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.4 Cost Estimates (Cont'd.)

the costs of the gasification, Chance process, and dolomite preparation areas where based on the Bureau of Mines Report.* The cost of the gasification and oil treatment areas of the COGAS process and the costs of the coal preparation, gasification, and raw gas quench areas of the K-T and Winkler processes were based on published and in-house information. The costs for the Selexol systems and Stretford plants for the three processes (where applicable) were obtained from Allied Chemical Corporation and Woodall Duckham (U.S.A.) Ltd. as ± 25% estimates. Costs for all other areas in all the three processes were based on previous definitive estimates and were developed by scaling the costs up or down and selecting factors based upon prior Dravo experience with coal conversion units.

The capital costs are order of magnitude type estimates with ±25% accuracy. Area costs include land surfacing costs, building costs, piping costs, electrical and instrumentation costs, foundation costs, etc. The Total Plant Investment includes area costs and all EP&C costs and license fees for a grass roots facility. The capital costs for purchased power generation and pipeline for raw water supply are not included in the estimate, nor are the costs for coal mine or delivery

*"Preliminary Economic Analysis of CO_2 Acceptor Process Producing 250 Million Standard Cubic Feet Per Day of High Btu Gas From Two Fuels: Subbituminous Coal & Lignite", U.S. Department of the Interior, Bureau of Mines, Process Evaluation Group, Morgantown, West Virginia, March, 1976.

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.4 Cost Estimates (Cont'd.)

of coal to battery limits and disposal of ash and sludge to landfill outside the battery limits. The costs include all provisions necessary to meet environmental requirements. (See Section 5.)

The cost of additional steam generation for power requirements is not provided. The additional steam requirements for the plant are provided by auxiliary coal and/or process fuel gas-fired boilers. The auxiliary coal-fired boilers are provided with an SO_2 removal area where SO_2 is scrubbed by the wet lime process; for the Lurgi process, the Wellman Lord system is used. Drying of the coal is accomplished by process flue gases with flue gases generated by burning coal and/or process fuel gas. These flue gases are scrubbed, if necessary, to reduce their SO_2 content, to meet environmental standards.

The parameters used in developing the Total Capital Requirements, the rate of return on investment, and the income tax are enumerated below:

1. Debt: Equity Ratio - 75:25
2. Interest on Debt - 9%
3. Return on Equity - 15%
4. Federal Income Tax - 48%
5. Construction Period - As shown on project schedules in Subsection 7.2.
6. Interest During Construction - Percent Interest Rate x Total Plant Investment x Construction Period x 0.5 x .01

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.4 Cost Estimates (Cont'd.)

7. Start-Up Costs - Full payroll and overhead for six months, coal for two months, 10% of annual supplies, and 1% of Total Plant Investment for correction.

8. Working Capital - Coal inventory for 45 days, 0.9% of Total Plant Investment for materials and supplies, and 1/24 of annual gas revenue at $4/MM Btu.

9. Local Taxes & Insurance - 2.7% of Total Plant Investment.

10. Depreciation - 20 years, straight line (5% of Total Fixed Investment.

11. Average Return on Rate Base = 0.0525 (C + W)
where C = Total Capital Requirement
W = Working Capital

12. Average Federal Income Tax = 0.0173 (C + W)

13. All costs are expressed in August, 1976 dollars. Escalations for future labor, materials, etc., are not included.

Gas Cost

Operating costs presented herein are direct plant costs based on 330 operating days per year, 150 MM SCFD of SNG production and 1000 TPD ammonia equivalent gas production. Calculations were made using the AGA/OCR utility financing method as adopted by the Synthetic Gas-Coal Task Force in their Final Report (April, 1973) to the Federal Power Commission. Parameters used in the calculations are as follows:

Coal	- Run-of-the-mine coal with 35.02% moisture @ $7/ton, delivered
Catalyst & Chemicals	- Individual costs were determined based on estimated requirements

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.4 Cost Estimates (Cont'd.)

Purchased Utilities
- Electric power, $0.007/KWH
- Raw Water, $0.50/acre foot (cost includes raw water delivery to plant site)

Labor:

Operating - Manpower x 2080 hrs/hr x $7/hr.

Maintenance - 1.5% of Total Plant Investment.

Supervision - 15% of Operating and Maintenance Labor.

Administration and General Overhead - 60% of total labor including operating, maintenance and supervision.

Supplies - 30% of annual Operating Labor and 100% of annual Maintenance Labor

By-Product Credits
- Ammonia synthesis gas @ $1.30/MM Btu
- Low sulfur hydrotreated syncrude @ $0.30/gal
- High sulfur oils @ $0.15/gal.
- Light hydrocarbons @ $0.15/gal.
- Claus sulfur (flakes) no credit
- Anhydrous Ammonia @ $150/ton
- Crude phenols @ 15¢/gal.
- Sulfuric Acid @ $50/ton

$$\text{Gas Cost} = \frac{\text{Total Revenue Requirement in Dollars/yr}}{\text{MM Btu/yr}}$$

where, MM Btu/yr = 150 MM SCFD x (Higher Heating Value of the SNG, Btu/SCF) x 330 days.

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.4 Cost Estimates (Cont'd.)

First Year Gas Cost: When calculating the first year gas cost, all of the above capital cost and gas cost parameters remain constant except the Return on Rate base and Federal Income Tax. For the first year, these two are calculated by the following formulae:

First Year Return of Rate Base = 0.078 (0.975C + 0.025W)

First Year Federal Income Tax = 0.0346 (0.975C + 0.025W)

where C = Total Capital Requirement

W = Working Capital

The first year gas costs were calculated for all processes by the above method. The results are tabulated below:

Process	First Year Gas Cost, $/MM Btu
B&W	6.41
CO_2 Acceptor	3.54
COGAS	4.89
HYGAS	3.07
Koppers-Totzek	6.80
Texaco	5.52
Winkler	5.56
Lurgi	3.61

PROCESS SELECTION STUDY
SNG FROM COAL
FOR
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BABCOCK & WILCOX

Capital Cost Estimate

Area No.	Description	MM $
01	Coal Unloading and Handling	17.0
02	Gasification	213.1
03	Gas Compression	16.9
04	Acid Gas Removal	36.6
05	Shift Conversion	33.0
06	Methanation	21.4
07	CO_2 Removal	56.0
08	Gas Compression and Dehydration	4.0
09	Oxygen Plant	170.4
10	Stretford Plant	9.7
11	Primary Water Treatment	18.8
12	Bio-Treatment	5.4
13	Demineralization and Deaeration	3.2
14	Cooling Water System	23.4
15	Treatment, Disposal and Evaporation	6.1
16	Sanitary Waste Disposal	.2
17	Flare	1.6
18	Emergency Power Generation	5.0
19	Plant Air and Instrument Air	2.2
20	Gas Surge	2.2
21	Fire Protection	.6
22	Offsites	65.0
	TOTAL	711.8
	Project Contingency + General & Administrative Expense + Engineering Supervision	85.4
	Process Contingency (5%) for Gasification	10.6
	TOTAL PLANT INVESTMENT	807.8
	Interest During Construction	157.4
	Start-up Costs	33.1
	TOTAL FIXED INVESTMENT	998.3
	Working Capital	21.7
	TOTAL CAPITAL REQUIREMENT	1,020.0

BABCOCK & WILCOX

Gas Cost Estimate

		MM $/yr	$/MM BTU
Coal		49.93	1.09
Operating Costs			
Catalyst & Chemicals:	9.17		
Purchased Utilities:			
Electricity:	16.48		
Water:	0.015		
Labor:			
Direct Operating:	3.93		
Maintenance:	12.12		
Supervision:	2.41		
Admin. & Gen.Overhead:	12.18		
Supplies:	13.30		
	Total	69.61	1.52
By-Product Credit:		(9.31)	(0.21)
Capital Costs:			
Local Taxes & Insurance:	21.81		
Depreciation:	49.91		
Average Return:	54.69		
Average Federal Income Tax:	18.02		
	Total	144.43	3.15
TOTAL REVENUE REQUIREMENT:		254.66	5.55

Dravo

PROCESS SELECTION STUDY
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FOR
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CO_2 ACCEPTOR

Capital Cost Estimate

Area No.	Description	MM $
01	Coal Unloading & Handling	14.6
02	Gasification	235.2
03	Chance Process	5.2
04	Acid Gas Removal	16.7
05	Methanation	23.8
06	Gas Compression and Dehydration	9.6
07	NH_3 Syngas Compression	4.5
08	Dolomite Preparation	.9
09	Claus Plant	2.0
10	Scot Plant	2.6
11	Primary Water Treatment	7.7
12	Bio Treatment	3.6
13	Demineralization and Deaeration	5.5
14	Cooling Water System	7.2
15	Treatment Disposal & Evaporation	2.4
16	Sanitary Waste Disposal	.2
17	Flare	1.6
18	Emergency Power Generation	5.0
19	Plant Air and Instrument Air	2.6
20	Gas Surge	2.2
21	Fire Protection System	.6
22	Offsites	55.2
	TOTAL	408.9
	Project Contingency + General & Administrative Expense + Engineering Supervision	49.1
	Process Contingency (5%) for Gasification	11.8
	TOTAL PLANT INVESTMENT	469.8
	Interest During Construction	70.4
	Start-Up Costs	21.7
	TOTAL FIXED INVESTMENT	561.9
	Working Capital	17.7
	TOTAL CAPITAL REQUIREMENT	579.6

CO_2 ACCEPTOR

Gas Cost Estimate

		MM $/yr	$MM BTU
Coal		41.46	0.88
Operating Costs			
Catalyst & Chemicals:	2.03		
Purchased Utilities:			
Electricity:	5.00		
Water:	.002		
Labor:			
Direct Operating:	3.06		
Maintenance:	7.05		
Supervision:	1.52		
Admin.& Gen.Overhead:	6.98		
Supplies:	7.97		
	Total	33.61	0.72
By-Product Credit:		(13.31)	(0.28)
Capital Costs:			
Local Taxes & Insurance:	12.68		
Depreciation:	28.10		
Average Return:	31.36		
Average Federal Income Tax:	10.33		
	Total	82.47	1.76
TOTAL REVENUE REQUIREMENT:		144.23	3.08

Dravo

PROCESS SELECTION STUDY
SNG FROM COAL
FOR
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COGAS

Capital Cost Estimate

Area No.	Description	MM $
01	Coal Unloading and Handling	21.9
02	Gasification	262.4
03	Gas Compression	85.5
04	Acid Gas Removal	54.7
05-1	Gas Purification	with area 04
05-2	Light H/C Recovery	with area 04
06	Shift Conversion	20.2
07	Methanation	20.1
08	Bulk CO_2 Removal	11.9
09	Gas Dehydration and Compression	6.8
10	Stretford Plant	12.1
11	Primary Water Treatment	7.0
12	Bio Treatment	with area 15
13	Demineralization and Dearation	7.2
14	Cooling Tower	11.0
15	Treatment Disposal and Evaporation	35.7
16	Sanitary Waste Disposal	with area 15
17	Thermal Oxidizer and Flare	2.8
18	Emergency Power Generation	3.1
19	Plant Air and Instrument Air	12.8
20	Gas Surge	2.2
21	Fire Protection System	1.1
22	Ammonia Recovery	3.6
23	SO_2 Removal	2.0
24	Offsites	65.8
	TOTAL	649.9
	Project Contingency + General & Administrative Expense + Engineering Supervision	77.9
	Process Contingency (5%) for Gasification	13.1
	TOTAL PLANT INVESTMENT	740.9
	Interest During Construction	122.3
	Start-up Costs	34.6
	TOTAL FIXED INVESTMENT	897.8
	Working Capital	23.7
	TOTAL CAPITAL REQUIREMENT	921.5

Dravo

Gas Cost Estimate

		MM $/yr	$/MM BTU
Coal		68.38	1.48
Operating Costs			
Catalyst & Chemicals:	6.24		
Purchased Utilities:			
Electricity:	2.70		
Water:	.01		
Labor:			
Direct Operating:	4.72		
Maintenance:	11.11		
Supervision:	2.37		
Admin.& Gen.Overhead:	10.92		
Supplies:	12.53		
	Total	50.60	1.10
By-Product Credit:		(58.93)	(1.28)
Capital Costs:			
Local Taxes & Insurance:	20.00		
Depreciation:	44.87		
Average Return:	49.60		
Average Federal Income Tax:	16.35		
	Total	130.82	2.83
TOTAL REVENUE REQUIREMENT		190.87	4.13

Dravo

PROCESS SELECTION STUDY
SNG FROM COAL
FOR
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HYGAS

Capital Cost Estimate

Area No.	Description	MM $
01	Coal Unloading and Handling	16.9
02	Gasification	118.4
03	Raw Gas Quench	16.7
04	Shift Conversion	18.2
05	Gas Cooling	6.4
06	Acid Gas Removal	16.8
07	Methanation	16.5
08	Glycol Dehydration	8.5
09	Oxygen Plant	48.0
10	Stretford Plant	8.6
11	Primary Water Treatment	7.0
12	Bio Treatment	10.9
13	Demineralization & Deaeration	4.7
14	Cooling Water System	7.5
15	Treatment, Disposal & Evaporation	2.4
16	Sanitary Waste Disposal	0.2
17	Flare & Thermal Oxidizer	2.0
18	Emergency Power Generation	5.0
19	Plant Air & Instrument Air	2.2
20	Gas Surge	2.2
21	Fire Protection System	.6
22	Boiler	33.3
23	SO_2 Removal	12.1
24	Offsites	35.5
	TOTAL	400.6
	Project Contingency + General & Administrative Expense + Engineering Supervision	48.1
	Process Contingency (5%) for Gasification	5.9
	TOTAL PLANT INVESTMENT	454.6
	Interest During Construction	88.6
	Start-Up Costs	23.4
	TOTAL FIXED INVESTMENT	566.6
	Working Capital	19.1
	TOTAL CAPITAL REQUIREMENT	585.7

Dravo

HYGAS

Gas Cost Estimate

		MM $/Yr.	$/MM BTU
Coal		49.51	0.98
Operating Costs:			
Catalyst & Chemicals:	3.05		
Purchased Utilities:			
Electricity:	5.05		
Water:	.005		
Labor:			
Direct Operating:	3.80		
Maintenance:	6.82		
Supervision:	1.59		
Admin.& Gen.Overhead:	7.32		
Supplies:	7.96		
	Total	35.60	0.70
By-Product Credit:		(35.12)	(0.70)
Capital Costs:			
Local Taxes & Insurance:	12.27		
Depreciation:	28.33		
Average Return:	31.75		
Average Federal Income Tax:	10.46		
	Total	82.81	1.64
TOTAL REVENUE REQUIREMENT:		132.80	2.62

PROCESS SELECTION STUDY
SNG FROM COAL
FOR
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KOPPERS-TOTZEK

Capital Cost Estimate

Area No.	Description	MM $
01	Coal Unloading and Handling	17.9
02	Gasification	228.8
03	Gas Compression	80.0
04	Acid Gas Removal	38.9
05	Shift Conversion	28.3
06	Methanation	21.6
07	CO_2 Removal	44.1
08	Gas Compression and Dehydration	4.5
09	Oxygen Plant	160.6
10	Stretford Plant	10.8
11	Primary Water Treatment	18.0
12	Bio-Treatment	2.7
13	Demineralization and Deaeration	3.3
14	Cooling Water System	19.3
15	Treatment, Disposal, & Evaporation	4.7
16	Sanitary Waste Disposal	.2
17	Flare	1.6
18	Emergency Power Generation	5.0
19	Plant Air and Instrument Air	2.2
20	Gas Surge	2.2
21	Fire Protection System	.6
22	Offsites	85.6
	TOTAL	780.9
	Project Contingency + General & Administrative Expense + Engineering Supervision	93.7
	TOTAL PLANT INVESTMENT	874.6
	Interest During Construction	170.4
	Start-Up Costs	35.0
	TOTAL FIXED INVESTMENT	1080.0
	Working Capital	23.0
	TOTAL CAPITAL REQUIREMENT	1103.0

KOPPERS-TOTZEK

Gas Cost Estimate

		MM $/yr	$/MM BTU
Coal		53.31	1.13
Operating Costs:			
Catalyst & Chemicals:	9.22		
Purchased Utilities:			
Electricity:	22.46		
Water:	0.015		
Labor:			
Direct Operating:	4.22		
Maintenance:	13.12		
Supervision:	2.60		
Admin.& Gen.Overhead:	11.96		
Supplies:	14.39		
	Total	77.99	1.65
By-Product Credit:		(9.31)	(0.20)
Capital Costs:			
Local Taxes & Insurance:	23.61		
Depreciation:	54.00		
Average Return:	59.11		
Average Federal Income Tax:	19.48		
	Total	156.20	3.31
TOTAL REVENUE REQUIREMENT:		278.19	5.89

Dravo

PROCESS SELECTION STUDY
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TEXACO

Capital Cost Estimate

Area No.	Description	MM $
01	Coal Unloading and Handling	17.6
02	Coal Drying and Pulverizing	with area 03
03	Gasification	210.2
04	Shift Conversion	29.1
05	Acid Gas Removal	25.5
06	Methanation	31.9
07	Gas Cooling	8.5
08	Glycol Dehydration	with area 07
09	Oxygen Plant	179.8
10	Stretford Plant	10.7
11	Primary Water Treatment	16.3
12	Bio-Treatment	10.0
13	Demineralization and Deaeration	4.8
14	Cooling Water System	23.3
15	Treatment, Disposal, and Evaporation	6.6
16	Sanitary Waste Disposal	.2
17	Flare	1.6
18	Emergency Power Generation	5.0
19	Plant Air and Instrument Air	2.2
20	Gas Surge	2.2
21	Fire Protection System	.6
22	Boiler	17.1
23	SO_2 Removal	4.8
24	Offsites	49.2
	TOTAL	657.2
	Project Contingency + General & Administrative Expense + Engineering Supervision	78.9
	Process Contingency (5%) for Gasification	10.5
	TOTAL PLANT INVESTMENT	746.6
	Interest During Construction	92.4
	Start-Up Costs	31.1
	TOTAL FIXED INVESTMENT	870.1
	Working Capital	21.5
	TOTAL CAPITAL REQUIREMENT	891.6

TEXACO

Gas Cost Estimate

		MM $/yr	$/MM BTU
Coal		50.89	1.09
Operating Costs:			
Catalyst & Chemicals:	8.40		
Purchased Utilities:			
Electricity:	6.67		
Water:	.012		
Labor:			
Direct Operating:	3.93		
Maintenance:	11.20		
Supervision:	2.27		
Admin.& Gen.Overhead:	10.44		
Supplies:	12.38		
	Total	55.30	1.18
By-Product Credit:		(9.31)	(0.20)
Capital Costs:			
Local Taxes & Insurance:	20.16		
Depreciation:	43.50		
Average Return:	47.94		
Average Federal Income Tax:	15.80		
	Total	127.40	2.72
TOTAL REVENUE REQUIREMENT:		224.28	4.79

Dravo

PROCESS SELECTION STUDY
SNG FROM COAL
FOR
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WINKLER

Capital Cost Estimate

Area No.	Description	MM $
01	Coal Unloading and Handling	18.0
02	Gasification	150.0
03	Gas Compression	57.0
04	Acid Gas Removal	36.6
05	Shift Conversion	23.6
06	Methanation	19.8
07	CO_2 Removal	31.0
08	Gas Compression and Dehydration	4.3
09	Oxygen Plant	94.2
10	Stretford Plant	8.9
11	Primary Water Treatment	17.7
12	Bio-Treatment	7.0
13	Demineralization and Deaeration	3.8
14	Cooling Water System	20.1
15	Treatment, Disposal, Evaporation	5.0
16	Sanitary Waste Disposal	.2
17	Flare	1.6
18	Emergency Power Generation	5.0
19	Plant Air and Instrument Air	2.2
20	Gas Surge	2.2
21	Fire Protection System	.6
22	Boiler	47.4
23	SO_2 Removal	14.7
24	Offsites	51.6
	TOTAL	622.5
	Project Contingency + General & Administrative Expense + Engineering Supervision	74.7
	TOTAL PLANT INVESTMENT	697.2
	Interest During Construction	115.1
	Start-up Costs	29.8
	TOTAL FIXED INVESTMENT	842.1
	Working Capital	21.2
	TOTAL CAPITAL REQUIREMENT	863.3

WINKLER

Gas Cost Estimate

		MM/$/yr	$/MM BTU
Coal		52.21	1.11
Operating Costs:			
Catalyst & Chemicals:	8.09		
Purchased Utilities:			
Electricity:	10.53		
Water:	.015		
Labor:			
Direct Operating:	3.64		
Maintenance:	10.46		
Supervision:	2.11		
Admin.& Gen.Overhead:	9.73		
Supplies:	11.55		
	Total	56.12	1.20
By-Product Credit:		(9.31)	(0.20)
Capital Costs:			
Local Taxes & Insurance:	18.82		
Depreciation:	42.11		
Average Return:	46.44		
Average Federal Income Tax:	15.30		
	Total	122.67	2.62
TOTAL REVENUE REQUIREMENT:		221.69	4.73

Dravo

PROCESS SELECTION STUDY
SNG FROM COAL
FOR
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LURGI

Capital Cost Estimate

Area No.	Description	MM $
1100	Gasification	86.5
1200	Shift Conversion	12.7
1300	SNG Gas Cooling	7.5
1400	Rectisol	40.6
1600	Phenosolvan & NH_3 Recovery	25.2
1700	Methanation	21.3
1800	Gas Liquor Separation	8.3
1900	Product Gas Compression and Drying	9.6
2000	Coal Preparation and Handling	46.5
3000	Air Separation Unit	50.5
4000	Sulfur Recovery	14.6
5000	Steam Generation and Distribution	80.9
5200	Stack Gas Scrubbing	20.4
5400	Raw Water Supply and Treating	15.4
5500	Cooling Water	10.7
5600	Fire Protection System	.8
5700	Miscellaneous Utilities	.8
6000	Offsite Storage and Loading Facilities	4.4
7000	Plant Interconnecting Piping	9.0
8100	Liquid Waste Effluent System	4.2
8200	Ash Disposal	3.3
8300	Flare System	2.5
	Offsites	24.3
	TOTAL	500.0*
	Project Contingency + General & Administrative Expense + Engineering Supervision	(Included in Total
	TOTAL PLANT INVESTMENT	500.0
	Interest During Construction	82.6
	Start-Up Costs	25.0
	TOTAL FIXED INVESTMENT	607.6
	Working Capital	19.5
	TOTAL CAPITAL REQUIREMENT	627.1

* Value derived by deleting the NH_3 synthesis section from the Lummus Estimate.

Dravo

LURGI

Gas Cost Estimate

		MM $/yr	$MM BTU
Coal		51.80	1.09
Operating Costs:			
Catalyst & Chemicals:	2.90		
Purchased Utilities:			
Electricity:	3.22		
Water:	.004		
Labor:			
Direct Operating:	3.73		
Maintenance:	7.50		
Supervision:	1.68		
Admin.& Gen.Overhead:	7.88		
Supplies:	8.62		
	Total	35.53	0.75
By-Product Credit:		(29.04)	(0.61)
Capital Costs:			
Local Taxes & Insurance:	13.50		
Depreciation:	30.38		
Average Return:	33.95		
Average Federal Income Tax:	11.19		
	Total	89.02	1.88
TOTAL REVENUE REQUIREMENT:		147.31	3.11

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.5 Overall Evaluation

The technical evaluation of the eight candidate processes is summarized in Subsection 7.3. In selecting a process, however, other aspects, such as economic and environmental must also be considered.

The following discussion evaluates the processes with respect to these aspects. This evaluation, as in the technical evaluation, is quantified by assignment of point ratings. The criteria covered, point ratings assigned, and justification of the assignment are presented below.

The criteria and the top ratings for each criterion are those suggested by Montana Trade Commission. (See the attached Overall Ratings table.)

Technical Evaluation (Top Rating = 15)

The technical evaluation ratings derived in Subsection 7.3 were reduced from the base of 75 to 15 to conform to the values assigned by Montana for the Overall Evaluation Rating. The adjusted technical evaluation ratings are listed below:

PROCESS	POINT RATINGS
B & W	11
CO_2 Acceptor	9
COGAS	9
HYGAS	9
K-T	14
Texaco	8
Winkler	13
Lurgi	14

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.5 Overall Evaluation (Cont'd.)

Thermal Efficiency (Top Rating = 15)

A high thermal efficiency results in a lower consumption of Montana's coal reserves and electric power. This criterion is important to the overall evaluation of the processes.

The process with the lowest thermal efficiency (K-T) was assigned "0" points and that with the highest thermal efficiency (HYGAS) 15 points. Point ratings for all other processes were interpolated using the percent thermal efficiencies and a straight-line relationship. The point ratings are listed below:

PROCESS	THERMAL EFFICIENCY, %	POINT RATINGS
B & W	44.7	1
CO_2 Acceptor	64.8	12
COGAS	58.1	9
HYGAS	69.8	15
K-T	42.2	0
Texaco	52.0	5
Winkler	50.8	5
Lurgi	60.1*	10

*Value derived from the Lummus Estimate by substituting for purchased power a coal equivalent of 10,000 Btu/KWH instead of heat equivalent of 3413 Btu/KWH.

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.5 Overall Evaluation (Cont'd.)

Gas Cost (Top Rating = 25)

This important criterion reflects the economics of the processes by weighing in proper proportion factors such as the total capital requirements, operating cost, and depreciation.

The process with the highest gas cost (K-T) was assigned 12 points, and that with the lowest gas cost (HYGAS) 25. Point ratings for all other processes were interpolated using the gas costs and a straight-line relationship. The point ratings are listed below:

PROCESS	GAS COST, $/MM BTU	POINT RATINGS
B & W	5.55	13
CO_2 Acceptor	3.08	23
COGAS	4.13	19
HYGAS	2.62	25
K-T	5.89	12
Texaco	4.79	17
Winkler	4.73	17
Lurgi	3.11	23

By-Product Marketability (Top Rating = 10)

A techno-economic advantage of a process is realized if the process produces by-products that are readily marketable and/or disposable.

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.5 Overall Evaluation (Cont'd.)

All the processes produce ammonia synthesis gas and sulfur as by-products. The 1000 TPD ammonia synthesis gas is a required product by the Montana Trade Commission and is, therefore, assumed to be marketable. In addition, anhydrous ammonia is also produced as a by-product by the CO_2 Acceptor, COGAS, HYGAS and Lurgi processes and would, therefore, also be marketable.

In this study, there is no credit assigned to sulfur produced as requested by Montana Trade Commission, although it is known from experience that elemental sulfur produced in Claus or Stretford plants is in demand by manufacturers of sulfuric acid and other chemicals.

The COGAS, HYGAS and Lurgi processes also produce a liquid hydrocarbon product. A market may exist for these products as fuels, chemical or refinery feedstocks, but the degree of marketability cannot be established at present.

Therefore, all processes producing only the ammonia synthesis gas, sulfur, and anhydrous ammonia are given the top rating of 10. Those processes producing liquid hydrocarbon by-products are given 8 points. The processes and the point ratings are listed below:

PROCESS	POINT RATINGS
B & W	10
CO_2 Acceptor	10
COGAS	8

Dravo

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.5 Overall Evaluation (Cont'd.)

HYGAS	8
K-T	10
Texaco	10
Winkler	10
Lurgi	8

Environmental Risk (Top Rating = 10)

All the processes under consideration should meet the environmental standards. (See Section 5.) However, some of these processes pose a greater risk than the others of polluting the environment because of their inherent characteristics. The processes are assessed on this basis here.

Because of the risk potential, the maximum rating assigned to any process is 6. The B&W, HYGAS, and Texaco processes are rated at 6 points.

Both K-T and Winkler are given 5 points, because in both of these processes about half of the ash in the incoming coal is entrained in the gas leaving the gasifier. This can be an environmental liability in case of a malfunction of the gas-cleaning equipment or the settling equipment used for scrubber water.

7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.5 Overall Evaluation (Cont'd.)

The CO_2 Acceptor process was given 5 points because the regenerator gas clean-up system has not been demonstrated. This system is to remove the entrained ash and dolomite particles from the regenerator gas. The regenerator gas also contains some combustibles, which have to be burned before discharge to the atmosphere.

Both Lurgi and COGAS processes have significant quantities of condensing oils and require treatment of sour water. The Lurgi treatment has been demonstrated on a commercial scale, and Lurgi is given 5 points. The COGAS process produces a combustor gas which contains combustibles and particle matter. The particle matter has to be removed and the combustibles have to be burned. The COGAS process is given 4 points.

The point ratings of the processes are listed below:

PROCESS	POINT RATINGS
B&W	6
CO_2 Acceptor	5
COGAS	4
HYGAS	6
K-T	5
Texaco	6
Winkler	5
Lurgi	5

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7.0 FINAL PROCESS EVALUATION (Cont'd.)

7.5 Overall Evaluation (Cont'd.)

Availability Schedule (Top Rating = 5)

The urgent need for synthetic natural gas in Montana, as illustrated in Section 3, requires that the proposed plant be constructed and in operation at an early date. Assuming that all the processes would be at the same stage of development, Project schedules prepared for this study indicates that the length of time required to full production is about the same for all processes. However, at this time, all the processes are not at the same stage of development and this will be the governing factor in the availability schedule.

The point ratings assigned are dependent upon the degree of development of the process. (See Subsection 7.2 and 7.3.) The point ratings are listed below:

PROCESS	POINT RATINGS
B&W	3
CO_2 Acceptor	1
COGAS	2
HYGAS	1
K-T	5
Texaco	2
Winkler	5
Lurgi	5

THE OVERALL EVALUATION RATINGS AND COMPARISON OF PROCESSES ARE SUMMARIZED IN THE FOLLOWING TABLES.

PROCESS SELECTION STUDY
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COMPARISON OF PROCESSES

PROCESS DATA	B&W	CO_2 ACCEPTOR	COGAS	HYGAS	K-T	TEXACO	WINKLER	LURGI
Raw Coal, TPD	21,614	17,946	29,600	21,434	23,079	22,029	22,603	22,425†
Oxygen, TPD	11,622	--	--	2,229	11,736	10,318	5,266	3,590†
Raw Water, GPM	19,476	5,847	14,689	7,121	18,189	17,356	17,877	6,080†
Purchased Electric Power, KW	297,200	90,100	48,700	91,200	435,200	120,500	189,900	58,000†
Area Estimate, Acres	275	275	425	285	305	265	275	285
SNG Product, Billion Btu/D	138.62	142.21	139.88	152.99	142.84	141.90	142.05	143.50†
Ammonia Synthesis Gas, TPD equivalent NH_3	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000†
By-product Sulfur, TPD	106.3	68.1	112.9	81.4	124	111	95	80 †
By-product Sulfuric Acid, TPD	--	--	--	--	--	--	--	110 †
By-product Ammonia, TPD	--	90	64.8	68	--	--	--	107 †
By-product Coal Oil, Tar & Naphtha bbl/d	--	--	--	--	--	--	--	3,625 †
Syncrude, bbl/d	--	--	10,180	--	--	--	--	--
Light Hydrocarbons, TPD	--	--	303	830	--	--	--	--
Crude Phenols, bbl/d	--	--	--	--	--	--	--	616 †
Operating Labor	270	210	324	261	290	270	275	256 †
Total Plant Investment, $MM	807.8	469.8	740.9	454.6	874.6	746.6	697.2	500.0*
Gas Cost, $/MM	5.55	3.08	4.13	2.62	5.89	4.79	4.73	3.11
First Year Gas Cost, $/MM Btu	6.41	3.54	4.89	3.07	6.80	5.52	5.56	3.61
Schedule Requirements, months	85	84	82	87	85	87	85	77 †
O.A. Thermal Efficiency, %	44.7	64.8	58.1	69.8	42.2	52.0	50.8	60.1**
Technical Evaluation Ratings (Top Rating = 75)	55	45	43	45	70	42	65	72
Overall Evaluation Ratings (Top Rating = 80)	44	60	51	64	46	48	55	65

* Value derived by deleting the NH_3 synthesis section from the Lummus Estimate.

**Value derived from Lummus Estimate by substituting for purchased power a coal equivalent of 10,000 Btu/KWH instead of heat equivalent of 3413 Btu/KWH.

† Lurgi/Lummus Estimate

PROCESS SELECTION STUDY
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OVERALL EVALUATION RATINGS

EVALUATION CRITERIA	B&W	CO_2 ACCEPTOR	COGAS	HYGAS	K-T	TEXACO	WINKLER	LURGI	TOP RATING
TECHNICAL EVALUATION	11	9	9	9	14	8	13	14	15
THERMAL EFFICIENCY	1	12	9	15	0	5	5	10	15
GAS COST	13	23	19	25	12	17	17	23	25
BY-PRODUCT MARKETABILITY	10	10	8	8	10	10	10	8	10
ENVIRONMENTAL RISK	6	5	4	6	5	6	5	5	10
AVAILABILITY SCHEDULE	3	1	2	1	5	2	5	5	5
TOTALS	44	60	51	64	46	48	55	65	80

Dravo

PROCESS SELECTION STUDY
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8.0 ALTERNATE PRODUCTS & BY-PRODUCTS

The plant designs presented in Section 7 produce synthetic natural gas (SNG) and a gas product for synthesis of ammonia. Alternate products such as oils, fertilizers, and miscellaneous hydrocarbons to meet market demands, can be produced by addition of facilities to the SNG plant. This section discusses some of the alternate processes available.

8.1 Oil Products

An oil product can be produced by integrating a coal liquefaction facility with the SNG plant. Coal liquefaction processes, such as Synthoil produce a heavy oil while SRC (Solvent Refined Coal) produces a heavy pitch-like solvent refined coal. Both products have a low sulfur content and have been suggested for use as fuels in power plants.

In both liquefaction processes, the coal is hydrogenated in a liquid phase. The effluent from the hydrogenation reactor contains product oil, char and a gas containing mainly hydrogen. This gas is separated from the oil and recycled to the hydrogenator. The separated char product can be transferred to the SNG plant and gasified along with the coal.

8.0 ALTERNATE PRODUCTS & BY-PRODUCTS (Cont'd.)

8.1 Oil Products (Cont'd.)

A portion of the main stream gas in the SNG plant, after CO shift, can be diverted and subjected to additional shift conversion to produce a pure stream of hydrogen as a feed for the coal hydrogenation reactor.

8.2 Syngas For Miscellaneous Products

The gas from the gasification section (syngas) of the SNG plant contains mainly CO, H_2, CO_2, H_2O and CH_4. By increasing gasifier capacity, a side stream from this gas can be utilized for production of various chemicals as described below:

8.2.1 Ammonia Synthesis

In all the eight processes described in Section 7, a stream of syngas is withdrawn from the SNG plant for separation of hydrogen and subsequent use of this hydrogen in ammonia synthesis. The separation of hydrogen can be accomplished by several methods, two of which are described here.

In the first method, the hydrogen rich gas is purified to remove carbon dioxide and water. The gas is passed through an acid gas removal system, such as Benfield, for CO_2 removal and then through a glycol dehydration unit or molecular sieve beds for drying. The purfied gas enters a cryogenic cold box which cools the gas to condense and remove the bulk of CO in the feed. The gas is then expanded

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8.0 ALTERNATE PRODUCTS & BY-PRODUCTS (Cont'd.)

8.2 Syngas For Miscellaneous Products (Cont'd.)

8.2.1 Ammonia Synthesis (Cont'd.)

in a turbine and fed to a nitrogen liquid wash column. Nitrogen is fed, from an air separation plant or a similar source, in excess, so that the product stream will have a H_2/N_2 ratio of 3:1 for ammonia synthesis. Hydrogen recovery from such a cryogenic unit will be 94-95% with less than 10 ppm of CO.

The second method uses Linde's pressure swing adsorption (PSA) unit. It basically consists of two molecular sieve beds operated cyclically for adsorption and desorption. The adsorption takes place at high pressure. The impurities are adsorbed and pure hydrogen passes through. During the desorption cycle, the pressure is reduced and impurities are purged with some of the hydrogen. These impurities may be used as fuel elsewhere in the plant. Sufficient nitrogen is mixed with the purified hydrogen to produce a H_2/N_2 stream with a 3:1 ration for ammonia synthesis. Overall hydrogen recovery from this unit is 70-80%, with less than 10 ppm of CO and CO_2 in the hydrogen.

The first method requires a larger capital investment than the second, because of the acid gas removal and dehydration systems required. However, the second method gives a lower overall hydrogen recovery, thus requiring a greater amount of feed gas for a given amount of pure hydrogen produced. The extra gas required increases the plant capacity requirement but does not seriously affect the

8.0 ALTERNATE PRODUCTS & BY-PRODUCTS (Cont'd.)

8.2 Syngas For Miscellaneous Products (Cont'd.)

8.2.1 Ammonia Synthesis (Cont'd.)

thermal efficiency because the separated impurities can be recycled for use as a fuel elsewhere in the plant. Further investigation will be required to make a selection between the two processes for a specific case.

8.2.2 Methanol Synthesis

Methanol is produced commercially by the following generalized reaction:

$$CO + H_2 \longrightarrow CH_3OH \quad \text{(exothermic)}$$

Partial oxidation of methane with steam is the normal route to produce a methanol synthesis gas.

Syngas for methanol production can also be produced by coal gasification. The H_2:CO ratio of the synthesis gas is adjusted to the desired level in a CO shift converter. A high H_2:CO ratio will yield a higher conversion to methanol, but the methanol stream will be diluted with hydrogen, which must be separated and recycled.

8.2.3 Synthetic Fuels by Fischer-Tropsch Synthesis

In Fischer-Tropsch synthesis, CO and H_2 are reacted catalytically to form olefins and paraffins:

$$x\ CO + yH_2 \xrightarrow{Fe} \text{Olefins} + CO_2 \quad \text{(exothermic)}$$

$$x\ CO + yH_2 \xrightarrow{Co} \text{Paraffins} + CO_2 \quad \text{(exothermic)}$$

This process was used in Germany during World War II to produce synthetic fuels. The SASOL plant in South Africa produces gasoline via this route from Lurgi synthesis gas.

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8.0 ALTERNATE PRODUCTS & BY-PRODUCTS (Cont'd.)

8.2 Syngas For Miscellaneous Products (Cont'd.)

8.2.3 Synthetic Fuels by Fischer-Tropsch Synthesis (Cont'd.)

The syngas from the gasification section of the SNG plant can be used as a feedstock for Fischer-Tropsch synthesis. The H_2:CO ratio can be adjusted by shift conversion to the requirements of the Fischer-Tropsch reactions. In the SASOL plant, the ratio of H_2:CO has ranged from 2.4 to 1.7.

Typical products of the Fischer-Tropsch synthesis are: butane, naphtha, gasoline, diesel fuel, alcohols, fuel oil, etc. including methane, CO, and H_2.

8.2.4 Carbon Monoxide and Hydrogen as Chemical Feedstock

Carbon moxoxide and hydrogen can be separated by several methods, two of which have been described in Subsection 8.2.1.

The CO can be used in chemical processing such as the Mond process for recovery of nickel. It can also be used as a chemical feedstock in the production of acetic and propionic acids, methyl acetate, ethyl propionate, acetyl formate, hydroxyacetic acid, etc.

H_2 is also a valuable feedstock. For example, it can be used in refineries for such typical hydrogen consuming processes as:

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8.0 ALTERNATE PRODUCTS & BY-PRODUCTS (Cont'd.)

8.2 Syngas For Miscellaneous Products (Cont'd.)

8.2.4 Carbon Monoxide and Hydrogen as Chemical Feedstock (Cont'd.)

- hydrogenation of polymer gasoline
- hydrogenation of pyrolysis gasoline
- hydrodesulfurization of petroleum
- hydrocracking of residues to produce gas oils
- hydrotreating of lubricating oils to improve stability
- isomerisation of naphtha for production of gasoline

Hydrogen is also used in other industries. For example, hydrogenation of vegetable oils, reduction of metals in powder metallurgy, and similar applications.

8.2.5 Industrial Fuel Gas (IFG)

Synthetic natural gas (methane) is useful in commercial applications because it can be used in existing natural gas combusiton equipment with only minor modifications. Syngas after acid gas removal, known as industrial gas, is less expensive than synthetic natural gas on a per million BTU basis. The thermal efficiency of IFG manufacturing is greater than that for Syngas and if the combustion equipment in an industrial facility is modified to burn the IFG, it can become economically attractive.

8.0 ALTERNATE PRODUCTS & BY-PRODUCTS (Cont'd.)

8.3 Other Alternate Products

The alternate products described in the previous subsection were derived from a syngas stream. In this subsection, alternate products derived from other streams and by-products are described.

8.3.1 Sulfuric Acid from Sulfur or SO_2

As an alternative to selling elemental sulfur, it may be used for the production of sulfuric acid. It has been found in the industry that a sulfuric acid plant with a capacity of 100 tons per day or lower is not economically feasible because of the high maintenance cost. All eight gasification processes yield enough sulfur to produce more than 200 tons per day of sulfuric acid. It is also necessary that the users of the sulfuric acid be within a 100 mile radius of the acid plant because of the high freight charges for transport of the acid.

The SO_2 containing flue gases in the Lurgi process are treated in a Wellman-Lord system which separates a concentrated stream of SO_2 from the flue gases. This SO_2 can be further converted to SO_3 and the SO_3 used to produce sulfuric acid.

8.3.2 Carbon Dioxide as By-product

The regenerator off-gas from the CO_2 removal system in the SNG plant can be utilized to generate a CO_2 product. The off-gas is primarily CO_2, saturated with moisture. If a CO_2 product were to be separated,

Dravo

8.0 ALTERNATE PRODUCTS & BY-PRODUCTS (Cont'd.)

8.3 Other Alternate Products (Cont'd.)

8.3.2 Carbon Dioxide as By-product (Cont'd.)

a low sulfur iron chrome shift catalyst will have to be used, so that the H_2S and COS are separated from the gas in the acid gas removal system and not simultaneously with the CO_2 in the CO_2 removal system. (Compare the scheme for the HYGAS process with that for Babcock & Wilcox in Section 7.)

An oil exploration firm has shown an interest in using carbon dioxide for their well pressurization operations. The market could be explored for similar applications.

8.3.3 Fertilizer Manufacture

Ammonia produced from syngas (Subsection 8.2.1) and by-product carbon dioxide can be used for production of urea.

Ammonia can also be reacted with the sulfuric acid produced (Subsection 8.3.1) to form another fertilizer, namely ammonium sulfate.

Dravo

9.0 RECOMMENDATION

This study was performed to review the coal gasification technology and recommend one or more of the processes that meet the requirements of the state of Montana.

Twenty-one processes were reviewed, and eight of these were evaluated in detail. Point ratings were assigned to the eight processes on the basis of the technical evaluation. These technical evaluation ratings were combined with thermal efficiency, gas cost, by-product marketability, availability, and environmental criteria to develop the overall evaluation ratings. (See Subsections 7.3 and 7.5.) The ratings are summarized below:

PROCESS	TECHNICAL EVALUATION RATINGS	OVERALL EVALUATION RATINGS
B & W	55	44
CO_2 Acceptor	45	60
COGAS	43	51
HYGAS	45	64
K-T	70	46
Texaco	42	48
Winkler	65	55
Lurgi	72	65
(Top Rating)	(75)	(80)

Although the commercially demonstrated processes, namely K-T, Winkler, and Lurgi, appear attractive on the basis of the technical evaluation ratings, the HYGAS, CO_2 Acceptor, and Lurgi processes receive the higher ratings in the overall evaluation.

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9.0 RECOMMENDATION (Cont'd.)

K-T and Winkler receive lower overall evaluation ratings mainly because of their low thermal efficiencies and high gas costs. The HYGAS and CO_2 Acceptor processes receive high overall evaluation rating because they have high thermal efficiencies and low gas costs. The Lurgi process also has a high thermal efficiency and low gas cost, and in combination with its high technical evaluation rating, it retains its high standing.

The overall evaluation ratings for the three candidate processes are so close that it is difficult to make a definitive selection of a single process. Accordingly, to compare the viability of the processes, factors such as commercial maturity must be emphasized. The Lurgi process has been demonstrated on a commercial scale, and the HYGAS and CO_2 Acceptor processes have been demonstrated on a pilot scale only.

Therefore, the Lurgi process is recommended because it is a commercially demonstrated, low-risk process with a high overall thermal efficiency and low gas cost.

As an alternate selection, HYGAS, a second generation process, is recommended because of its very high overall thermal efficiency and low gas cost.

The CO_2 Acceptor process is recommended as an alternate second generation process if conditions beyond those considered in this report would require an alternate selection.

APPENDIX A

APPENDIX A

A COMPENDIUM OF FEDERAL, STATE, AND LOCAL EMISSION STANDARDS AS APPLICABLE TO GLASGOW, MONTANA

Prepared For

DRAVO CORPORATION

By

MORRISON-MAIERLE, INC.
Helena, Montana

August, 1976

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A COMPENDIUM OF FEDERAL, STATE, AND LOCAL EMISSION STANDARDS

AS APPLICABLE TO

GLASGOW, MONTANA

1.0 INTRODUCTION

The State of Montana has charged its Department of Health and Environmental Sciences with the responsibility of establishing and administering standards for air, water, and land quality. State supervision of effluent permit programs was provided for by Congress in the enabling legislation of the U.S. Environmental Protection Agency which states:

"....the Administrator (of the Environmental Protection Agency) shall authorize a State, which he determines has the capability of administering a permit program, which will carry out the objective (of restoring and maintaining the intergrity of the Nations environment), to issue permits for discharges.... PL 92-500, et al

The body of this report shall be devoted to the specific environmental regulations which establish permissible emission quantities, concentrations, and stability for gaseous, liquid, and solid effluents.

Generally speaking, Federal regulations take precidence over State regulation and State regulations over local regulations except the standard which affords the greatest protection to the environment is usually respected. Also, all permits are screened individually for possible synergistic effects that would cause the specified maximum permissible discharge limitations to be revised downward.

2.0 AQUEOUS STREAMS

Because of the predominant use of surface streams in the area surrounding the proposed gasification plant as a source of drinking water, the Federal Drinking Water Quality Regulations and the Montana Water Quality Standards will determine the permissible amounts of effluent emission. Emission permits are based upon proven stream flow records and the critical flow of the receiving stream. The critical flow is defined as being the discharge of the 10 year - 7 day low flow period.

2.1 CHLORIDES

A. Federal Standards

i. U.S. Public Health Service (U.S. PHS) - 250 parts per million (ppm)
ii. Federal Water Pollution Control Administration (FWPCA) - 250 ppm
iii. Environmental Protection Agency (EPA) - 250 ppm

B. State Standards

i. Montana Department of Health and Environmental Sciences 2000 milligrams per liter (mg/l)

C. Local Standards

i. Valley County - same as State
ii. City of Glasgow - same as State

2.2 PHENOLS

A. Federal Standards

i. USPHS - 0.001 ppm
ii. FWPCA - 0.001 ppm

B. State Standards. The Montana Water Quality Standards state that concentrations of toxic organic compounds are not to exceed the recommended limits contained in the 1962 U.S. Public Health Service Drinking Water Standards. The concentration of phenols as established by this publication is not to exceed 0.001 mg/l.

C. Local Standards

i. Valley County - same as State standards
ii. City of Glasgow - same as State standards

2.3 ORGANIC ACIDS

This is an effluent parameter which has not been rigidly defined by Federal or State regulatory agencies. Petitions for permits are taken under advisement on a case-by-case basis and are judged on the specific nature of the contaminant and its susceptibility to formation of organic chlorides. The Montana Water Quality Standards state that maximum allowable concentrations are to be less than "acute or chronic problem levels as revealed by bioassay or other methods".

2.4 SODIUM AND AMMONIUM IONS

A. Sodium

i. Federal Standards

a) EPA - 270 ppm

ii. State Standards - judged on a case-by-case basis. Concentrations are not to exceed "acute or chronic problem levels as revealed by bioassay or other methods".

iii. Local Standards

a) Valley County - same as State standards
b) City of Glasgow - same as State standards

B. Ammonia

i. Federal Standards - none
ii. State Standards - same as for sodium concentrations. As an example of the magnitude of an effluent limitation which the State may permit and its interpretation of the "10-year, 7-day low flow period" requirement, the following emission quantities are offered:

Exxon permit (Permit No. Mt-0000477) for discharge from their oil refinery at Billings, Montana into the Yellowstone River.

Daily Average - 301 lbs./day
Daily Max. - 662 lbs./day
Min discharge of Yellowstone River - 430 cfs

2.5 SUSPENDED OIL OR TAR

A. Federal Standards

i. EPA - 10 mg/l
ii. FWPCA - water should be free from oil and grease

B. State Standards

i. Montana Department of Health and Environmental Sciences 10 mg/l

C. Local Standards

i. Valley County - same as State standards
ii. City of Glasgow - same as State standards

2.6 SUSPENDED COAL OR ASH

A. Federal Standards

i. EPA - 30-50 ppm
However this standard implies a limitation on the BOD_5 or COD effluent concentrations because of the organic and reactive nature of the parameter.

B. State Standards

i. Determined on a case-by-case basis. Concentrations are not to exceed "acute or chronic problem levels as revealed by bioassay or other methods".

C. Local Standards

i. Valley County - same as State standards
ii. City of Glasgow - same as State standards

2.7 SANITARY WASTE

A. Federal Standards

Odor; FWPCA - nonoffensive
pH; EPA - 6.0 to 8.5
Temperature; EPA - 85° F at receiving water
D.O.; FWPCA - greater than or equal to 4 mg/l
C.O.D.; EPA - 60 mg/l
B.O.D_5; 30 ppm
T.D.S.; FWPCA - 500 mg/l
T.S.S.; EPA - max for any one day = 70 mg/l - average of daily values for 30 consecutive days shall not exceed 35.0 mg/l
Nitrate - as N; EPA - 10 ppm
Nitrite - as N; EPA - 1.0 ppm
Coliform; Drinking Water Quality Regulations -

Analysis by Membrane Filter Technique*/ Coliforms shall not exceed:
4 per 100 ml. in more than one sample if less than 20 samples collected per month, or
4 per 100 ml. in more than 5% of samples if 20 or more samples are examined per month.
Analysis by Fermentation Tube Technique, 10 ml. portion*/ Coliforms shall not be present in more than 10% of portions per month. Not more than one sample may have three or more portions positive when less than 20 samples are examined per month, or
Not mroe than 5% of samples may have three or more portions positive when 20 or more samples are examined per month.
Analysis by Fermentation Tube Technique, 100 ml. portion*/ Coliforms shall not be present in more than 60% of the portions per month,
Not more than one sample may have all five portions positive when less than five samples are examined per month, or
Not more than 20% of samples may have all five portions positive when five samples are examined per month.

* If sampling rate is less than four per month, compliance shall be based on a three month period unless state determines that a one month period shall apply.

B. State Standards

Odor - nonoffensive

pH - induced variation of pH within the range of 6.5 to 9.0 is to be less than 0.5 pH unit. Natural pH outside this range is to be maintained without change. Natural pH above 7.0 shall be maintained above 7.0.

Temperature - 3° F maximum increase above naturally occurring water temperature is allowed within the range of 32° F to 77° F; within the naturally occurring range of 77° F to 79.5^{o} F, no thermal discharge is allowed which will cause the water temperature to exceed 80° F; and where the naturally occurring water temperature is 79.5^{o} F or greater, the maximum allowable increase in water temperature is 0.5^{o} F. A 2° F per hour maximum decrease below naturally occurring water temperature is allowed when the water temperature is above 55° F, and a 2° F to 32° F.

D.O. - concentration is not to be reduced below 5.0 mg/l.

C.O.D. - 60 mg/l.

B.O.D. - 30 mg/l.

Nitrate (NO_3) - 45 mg/l.

Coliform - average number of organisms in the fecal coliform group is not to exceed 200 per 100 milliliters nor are 10% of the total samples during any 30-day period to exceed 400 fecal coliforms per 100 per 100 milliliters nor are 20 percent of the samples to exceed 1000 coliforms per 100 milliliters during any 30-day period.

C. Local Standards

i. Valley County - same as State standards
ii. City of Glasgow - same as State standards

2.8 HEAVY METAL IONS

The allowable emissions of these pollutants are most often decided on a case-by-case basis with limitations based on total effluent emissions of suspended and dissolved materials. The absolute allowable maximum discharge of any one constituent are as follows:

A. Federal Standards

i. Drinking Water Quality Regulations

Arsenic - 0.05 mg/l
Barium - 1.0 mg/l
Cadmium - 0.010 mg/l
Chromium - 0.05 mg/l
Lead - 0.05 mg/l

Mercury - 0.002 mg/l
Selenium - 0.01 mg/l
Silver - 0.05 mg/l

ii. EPA Coal Mining Effluent Guidelines and Standards

Iron (total) - max. for one day - 7.0 mg/l
average for 30 consecutive days shall not exceed 3.5 mg/l

Iron (dissolved) - max. for one day - 0.6 mg/l
average for 30 consecutive days shall not exceed 0.3 mg/l

Maganese - max. for one day - 4.0 mg/l
average for 30 consecutive days shall not exceed 0.3 mg/l

B. State Standards

Arsenic - 0.01 mg/l
Copper - 1.0 mg/l
Iron - 0.3 mg/l
Manganese - 0.05 mg/l
Zinc - 5.0 mg/l
Barium - 1.0 mg/l
Cadmium - 0.01 mg/l
Chromium (Cr+6) - 0.05 mg/l
Lead - 0.05 mg/l
Selenium - 0.01 mg/l
Silver - 0.05 mg/l

2.9 FLOURIDES

A. Federal Standards

Flouride - @ 53.7^{o} F & below* - 2.4 mg/l

@ 53.8^{o} F to 58.3^{o} F* - 2.2 mg/l
@ 58.4^{o} F to 63.8^{o} F* - 2.0 mg/l
@ 63.9^{o} F to 70.6^{o} F* - 1.8 mg/l
@ 70.7^{o} F to 79.2^{o} F* - 1.6 mg/l
@ 79.3^{o} F to 90.5^{o} F* - 1.4 mg/l

* annual average of maximum daily air temperatures

B. State Standards

Flouride - @ 50.0^{o} F to 53.7^{o} F* - 1.7 mg/l

@ 53.8^{o} F to 58.3^{o} F* - 1.5 mg/l
@ 58.4^{o} F to 63.8^{o} F* - 1.3 mg/l
@ 63.9^{o} F to 70.6^{o} F* - 1.2 mg/l
@ 70.7^{o} F to 79.2^{o} F* - 1.0 mg/l
@ 79.3^{o} F to 90.5^{o} F* - 0.8 mg/l

* annual average of maximum daily air temperatures

C. Local Standards

i. Valley County - same as State standards
ii. City of Glasgow - same as State standards

3.0 GASEOUS STREAMS

The predominate air quality standards in the State of Montana are those delineated in the Montana Air Quality Rules as established by the Clean Air Act of Montana. AT present the EPA is in the preliminary stage of developing air quality standards and these may be available in another year. The emission standards which follow are those as established in the Montana Air Quality Rules. They are also those adopted by Valley County, Montana.

3.1 HYDROGEN SULFIDE

Concentrations are based on measurements utilizing the methylene blue method with acetate tape for screening and monitoring.

Maximum Permissible Concentrations:

i. 0.03 ppm, 1/2-hour average, not to be exceeded more than twice in any five consecutive days.

ii. 0.05 ppm, 1/2-hour average, not to be exceeded over twice a year.

3.2 SULFUR OXIDES

A. Sulfur Dioxide - concentrations based on measurements utilizing the West-Gaeke or conductometric method.

Maximum Permissible Concentrations:

i. 0.02 ppm, maximum annual average.

ii. 0.10 ppm, 24-hour average, not to be exceeded over one percent of the days in any 3-month period.

iii. 0.25 ppm, not to be exceeded for more than one hour in any four consecutive days.

B. Reactive Sulfur (Sulfation) - concentrations based on measurements utilizing lead-peroxide candle method.

Maximum Permissible Concentrations:

i. 0.25 mg. sulfur trioxide per 100 cubic centimeters per day, maximum annual average.

ii. 0.50 mg. sulfur trioxide per 100 cubic centimeters per day, maximum for any one month period.

C. Suspended Sulfate - concentrations based on measurements utilizing a high volume sampler and the turbidmetric procedure.

Maximum Permissible Concentrations:

i. 4 micrograms per cubic meter of air, maximum annual average.

ii. 12 micrograms per cubic meter of air, not to be exceeded over one percent of the time.

D. Sulfuric Acid Mist -

Maximum Permissible Concentrations:

i. 4 micrograms per cubic meter of air, maximum annual average.

ii. 12 micrograms per cubic meter of air, not to be exceeded over one percent of the time.

iii. 30 micrograms per cubic meter of air, hourly average, not to be exceeded over one percent of the time.

3.3 NITROGEN OXIDE

There are no standards established by the State pertaining directly to this parameter. Instead, the State has adopted the nitrogen oxide emission limitations as outlined in the Standards of Performance for Fossil-Fuel Fired Steam Generators (39 FR 20791, June 14, 1974).

Maximum Permissible Concentrations:

1.26 grams per million calorie heat input (0.70 pound per million Btu) derived from a solid fossil fuel (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).

3.4 CARBON DIOXIDE

Standard not available at this time. Standard is in preliminary adoption stage. Individual permits are issued on a case-by-case basis.

3.5 PARTICULATES

Maximum Permissible Concentrations:

A. Total Suspended Particulate - concentrations measured with high volume sampler.

i. 75 micrograms per cubic meter of air, annual geometric mean.

ii. 200 micrograms per cubic meter of air, not to be exceeded more than one percent of the days of the year.

B. Settled Particulate (dustfall) - as measured by a container open to the atmosphere.

i. 15 tons per square mile, per month, 3-month average in residential area.

ii. 30 tons per square mile, per month, 3-month average in heavy industrial areas.

4.0 SOLID WASTE

4.1 FEDERAL REGULATIONS

The ensuing recommendations are condensed from the Federal Register, Vol. 39, No. 158 - Wed., August 14, 1974, "Thermal Processing and Land Disposal of Solid Waste". Referral to the publication should be made to review the regulations in their entirety.

i. Sites are to be located or protected by dikes, trenches, or other means in such a manner as to prevent ground and surface water pollution. If site is located in a flood plain, protection against at least the 50-year design flood should be provided by similar means.

ii. Leachate collection and treatment systems should be used whenever necessary to protect ground and surface water resources.

iii. Dust control measures should be initiated as necessary to protect the health and safety of facility personnel, nearby residents, and persons using the facility.

iv. Daily cover should be applied regardless of weather; sources of covers material should be accessible on all operating days. The thickness of the compacted daily cover should not be less than six inches.

v. Final cover should be applied on each area as it is completed or if the area is to remain idle for over one year. The thickness of the compacted final cover should not be less than two feet. Procedures to promote vegetative cover should then be initiated as promptly as possible.

4.2 STATE REGULATIONS

The ensuing standards are taken from the regulations outlined in Rule 16-2.14(2)-S14100, "Refuse Disposal Areas", as published by the Montana Department of Health and Environmental Sciences.

The disposal sites are classified on a case-by-case basis as being either of Group I or Group III. Determination is based upon concentrations of heavy metals, caustics, acids, and synthetic organic chemicals. If natural radioactivity levels are high, special provision must be made for disposal of radioactive wastes.

Local standards are adopted from State regulations.

A. Disposal Sites:

i. Group I sites shall not allow discharge of the afore-mentioned pollutants or their by-products to ground or surface waters. Sites must either confine the wastes to the disposal site, with no likelihood that the wastes will escape or they must be situated in a location where the leachate from the wastes can percolate only into underlying formations which have no hydraulic continuity with usable waters.

ii. Group III sites may contain water such as in marshy areas, deep gravel pits which contain exposed groundwater, or in areas which may be periodically flooded, such as along stream flood plains. Sites shall not be located on the banks or in a live or ephemeral stream.

B. Waste Disposal Specifications:

(a) Applying to both groups: Operational plan, design, and location shall be approved by the Montana Department of Health and Environmental Sciences and any other agencies it deems necessary to ensure public health. Site geology, hydrology, and climatology and site conditions will be reviewed.

(b) Pertaining to Group I sites only:

i. Sites shall be fenced to prevent animals from entering.

ii. Sites shall be supervised during operational hours.

iii. Sites shall be covered with six inches of compacted dirt at the end of each operational day.

iv. Proximity to population centers shall be determined on a case-by-case basis by the Department.

(c) Pertaining to Group III sites only:

i. Sites whall be covered with dirt from time to time or when the Department feels it necessary to prevent the sites from becoming an eye-sore.

ii. Sites are to be located in such a manner as to allow for re-use of the land and to preserve aesthetic values.

C. Site Selection - Major Conditions Pertaining Only to Group I sites:

i. Sites shall not be subject to flooding by surface water and/or have a high groundwater table and shall not be located within a 100-year flood plain.

ii. Sites shall not be located where underlying geological formations contain rock fractures or fissures which might lead to pollution of underground waters.

iii. Sites shall not be located in areas where springs exist.

D. Operation and Maintenance - Reclamation:

Upon completion of the filling operation at the refuse disposal area, a final compacted cover of at least two feet of suitable earth material shall be placed within one week after the final deposit of refuse at any portion of such refuse disposal area, unless an exemption in writing is granted by the Montana Department of Health and Environmental Sciences.

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Mr. Daniel Frazer, Water Quality Bureau, Helena, Montana

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Valley County, Montana

Mr. Danial Kinshella, County Sanitarian, Glasgow, Montana

APPENDIX B

APPENDIX B

FINAL REPORT

Montana Natural Gas Requirements and Natural Resources

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FINAL REPORT

On June 16, 1976 Dravo Corporation issued Purchase Order No. CP-7024-2 to Avco Everett Research Laboratory, Inc. to perform a series of services relevant to their evaluation of coal gasification processes for the Montana Trade Commission. The scope of the work was delineated in nine tasks described in the purchase order. Although most of the information pertaining to these tasks were communicated to Dravo through memoranda, telephone conversations, and meetings, a summary of the information developed during performance of these services is given in this final report, required by the purchase order.

Task 1 - Natural Gas Demand

The current use (1975) of natural gas in Montana has been set at 75 billion (75,305,980,000) cubic feet per year. This total can be divided into the following proportions: residential 30%, commercial 25%, industrial 44%, other uses 1%. Published use figures are shown in Table I.

Table I

1975 Natural Gas Use in Montana

Residential	22,933,270,000 ft^3
Commercial	18,845,859,000
Industrial	32,773,792,000

Projected useage is complicated by the pending curtailment in the supply of natural gas from Canada (discussed under Task 2). The demand had shown a steady growth, reaching a peak at about 80 billion cubic feet a year in 1973. The energy crisis of that year, and the subsequent announcement by the Canadian government to systematically reduce quantities of natural gas exported and at the same time to increase prices, curtailed expanded use of natural gas in Montana and led many to reduce their requirements. These actions led to an immediate drop in demand from the 80 billion cubic feet in 1973 to 75 billion in 1975. Additional reduction in demand can be anticipated but the magnitude of the reduction will depend on the reliability and cost of the supply. A computer study to project the reduction in demand with increasing cost is currently being sponsored by the Montana Trade Commission but its results are not expected until mid October.

Task 2 - Natural Gas Supply

The supply of natural gas to the state of Montana can be divided into two major sources (1) that imported from Canada and (2) that from wells in Montana and neighboring states. In 1975, 42.1 billion feet^3 were imported from Canada and 35 billion feet^3 were obtained from domestic sources. The imminent supply problem arises from the planned systematic curtailment of the Canadian supply. In 1973, Canadian imports totalled 49 BCF. They were reduced to the current 42 BCF level and are scheduled to be further reduced to 29 BCF in 1977. Additional reductions are scheduled until the supply diminishes

completly in 1989. A suggested variation of the scheduled reductions would have Canada maintain a level of about 29 BCF a year from 1977 to 1985 followed by drastic reductions to zero in 1987. The exact schedule appears to be somewhat negotiable, much depending on the counter-measures taken by the State of Montana.

The supply may also be considered from the aspect of the two companies which distribute the natural gas in the State of Montana. In 1975, the Montana Power Co. (MPC) distributed about 54 BCF in central and western Montana while the Montana-Dakota Utility (MDU) distributed about 21 BCF in eastern sections. The scheduled Canadian curtailment will not have a direct effect on the eastern sections as MDU relies entirely on domestic sources but it will have a major effect on MPC operations as MPC relies on Canadian imports for about 75% of its supply. A curve projecting the deficit between supply and demand in Montana for the period to 1993 due to the reduction in Canadian imports is presented in Figure 1.

Similar but slightly different supply and demand data was collected by the Montana Energy Advisory Council and presented to the Citizens Advisory Committee on Energy at a meeting in Helena on June 14, 1976 and is presented in Table II. This data indicates that, as far as the domestic supply is concerned, Montana is an exporter of natural gas. The deficit between exports and imports is essentially due to the 15 BCF exported by the Northern Natural Gas Co. as the amount exported by MDU to the Dakotas is essentially balanced by MDU's imports from Wyoming. The impact of the loss of 42 BCF from Canada, however, is still the dominant factor in the supply projections.

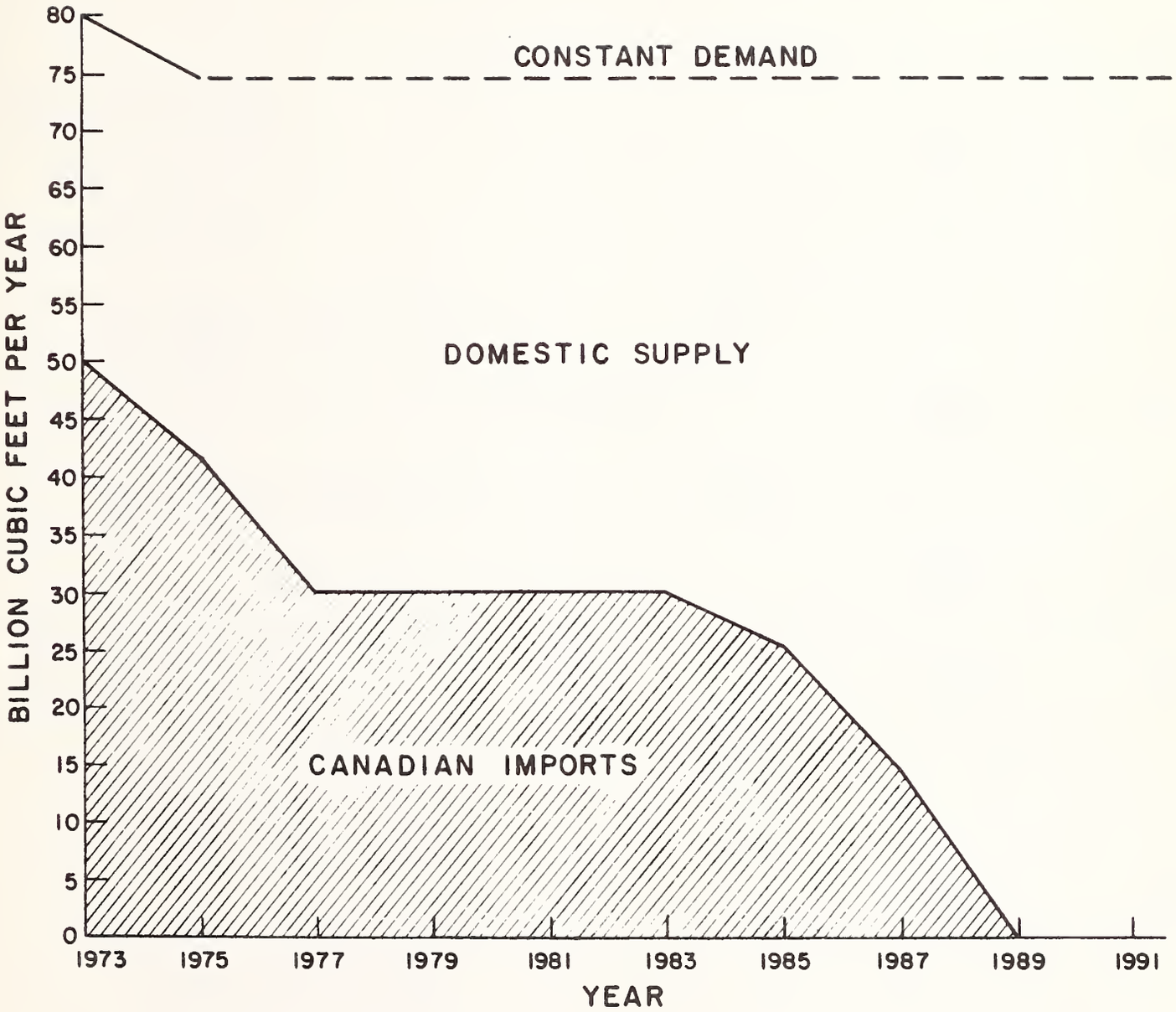


Figure 1. Projected Montana Supply/Demand of Pipeline Gas

Table II

1975 Montana Natural Gas Supply and Demand
(billion cubic feet at 14.73 psia)

Natural Gas Supply			
Montana Production		44.5	33%
Imports, Total		69.1	51%
MDU Imports from Wyoming	23.4		
MDU Imports from N. Dakota	3.5		
MPC Imports from Canada	42.2		
Withdrawals from Montana Storage, Total		22.1	16%
MDU Storage Withdrawals	13.1		
MPC Storage Withdrawals	9.0		
TOTAL SUPPLY		135.7	100%
Natural Gas Disposition			
Exports, Total		39.2	29%
MDU Exports to N. Dakota	11.0		
MDU Exports to S. Dakota	12.6		
MPC Exports to Canada	0.1		
Northern Natural Exports	15.5		
Injection to Montana Storage		13.1	10%
MDU Storage Injection	4.0		
MPC Storage Injection	9.1		
Montana Sales, Total		78.1	57%
Residential/Commercial	45.4		
Industrial	32.7		
Losses, Pipeline and Gas Company Use, and Unaccounted for Gas		5.3	4%
TOTAL DISPOSITION		135.7	100%

Ref: Nybo and T. Wheeling, Montan Energy Advisory Council Staff Paper 76-2, June 1976

Task 3 - Plant Size

Based on the fact that the Montana Trade Commission had earlier let a contract to Lurgi for the preliminary design of a coal gasification plant to produce 150 MMSCF/D of SNG plus 1000 tons/day of ammonia it was decided that a plant equivalent in thruput should be used for comparison purposes. Construction of a plant this size would more than replenish the loss in Canadian imports. Of course, a smaller plant,perhaps as small as 85 MMSCFD, could be adequate if a limited amount of conservation and a reduction in demand could be assumed. The storage capacity of MPC and MDU which together equal more than 250 billion cubic feet should be considered in the sizing and/on stream requirements of the plant.

Task 4 - Oil Supply and Demand

The supply and demand of oil in Montana, like natural gas, is directly related to the Canadian government's plan to curtail exports of fuel to the United States. The plan projects a systematic reduction in crude oil exports until 1982 at which time the exporation to refineries in Montana will be completely discontinued. The amount of oil imported from Canada represents between 30 and 40% of the crude oil and condensate refined in the state. Projecting a constant demand, based on current data; this would mean up to a 40% deficit (see Footnote #1) in supply by the year 1982. New sources of supply, e.g. increased in-state drilling and production, curtailment of Montana exports, the Alaskan pipeline, imports from lower 48 states or conversion of coal to liquid petroleum products, are possibilities.

Data on the quantity of crude and condensate oil refined in Montana for the years of 1960 through 1975 (based on Montana Oil and Gas Conservation Division data) are given in Figure 2. Projections based on constant supply from Montana and Wyoming wells but with the planned reduction in Canadian imports are included as a dashed line through 1985. Figure 3 shows the consumption by usage of petroleum products in Montana according to Bu Mines data. It is felt that Figures 2 and 3 are consistent within themselves but should not be compared to each other. (See Footnote #1)

From additional Bu Mines data, it is also evident that Montana exports appreciable quantities of crude oil. That is, for example, in 1973 when (according to Bu Mines) Montana imported 13,012,000 bbls from Canada it exported 22,591,000 bbls. Reassignment of a portion of these out-of-state shipments could obviously offset the decline in Canadian imports. Of course, problems arising out of the curtailment of interstate commerce would have to be considered.

Footnote #1 - - Figure 2 is based on data collected by the Montana Oil and Gas Conservation Division. It was developed by this agency from reports of (a) total crude oil refined and total Canadian imports from individual refineries in Montana, and (b) Montana production of crude oil delivered to refineries from oil transporters in Montana. There is a discrepancy between this data and that reported by the Bureau of Mines, (given in Figure 3) who base their numbers on refinery receipts. For example, for 1973 the Montana agency reports

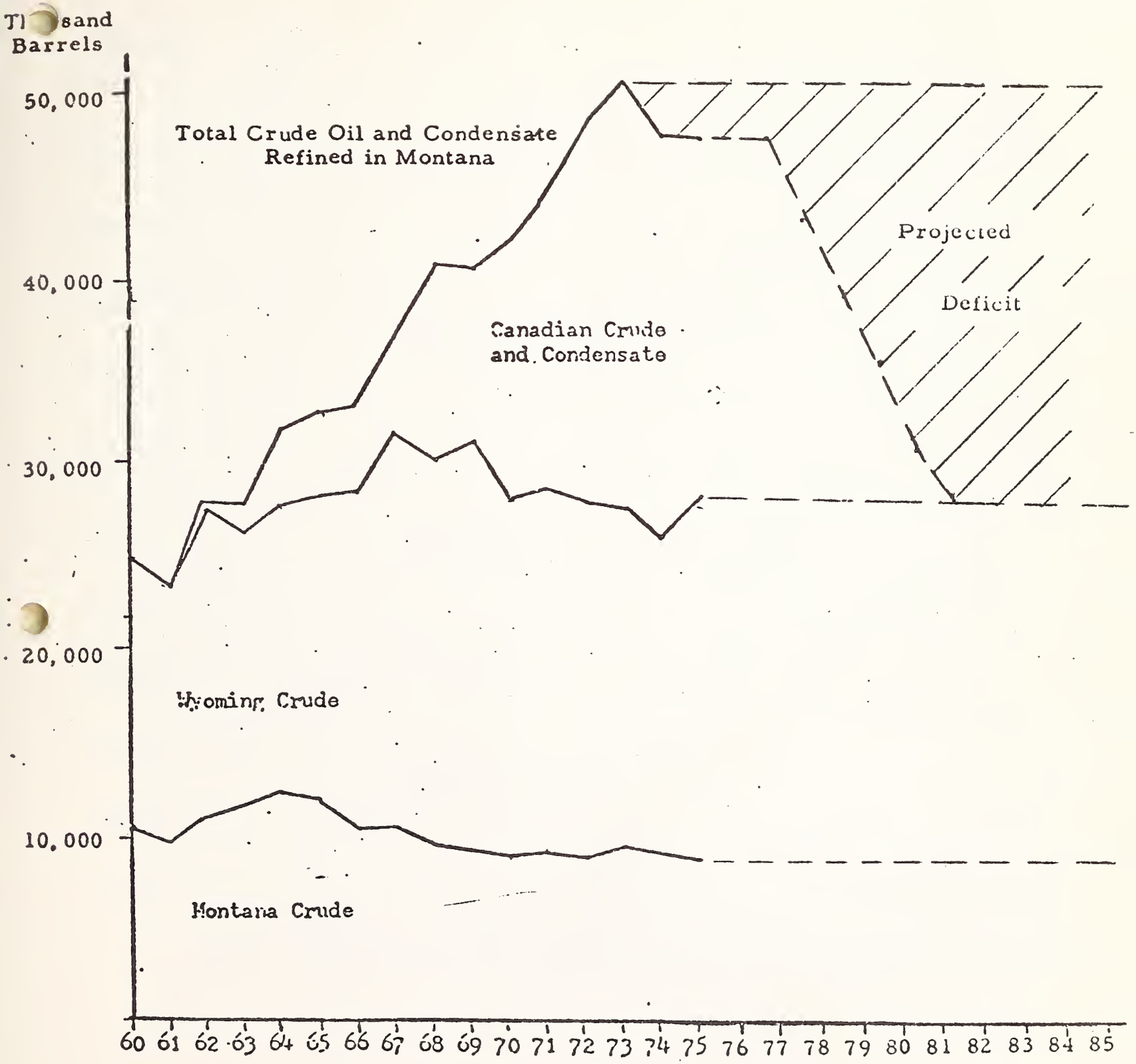


Figure 2

Petroleum Refined in Montana
by Source of Crude

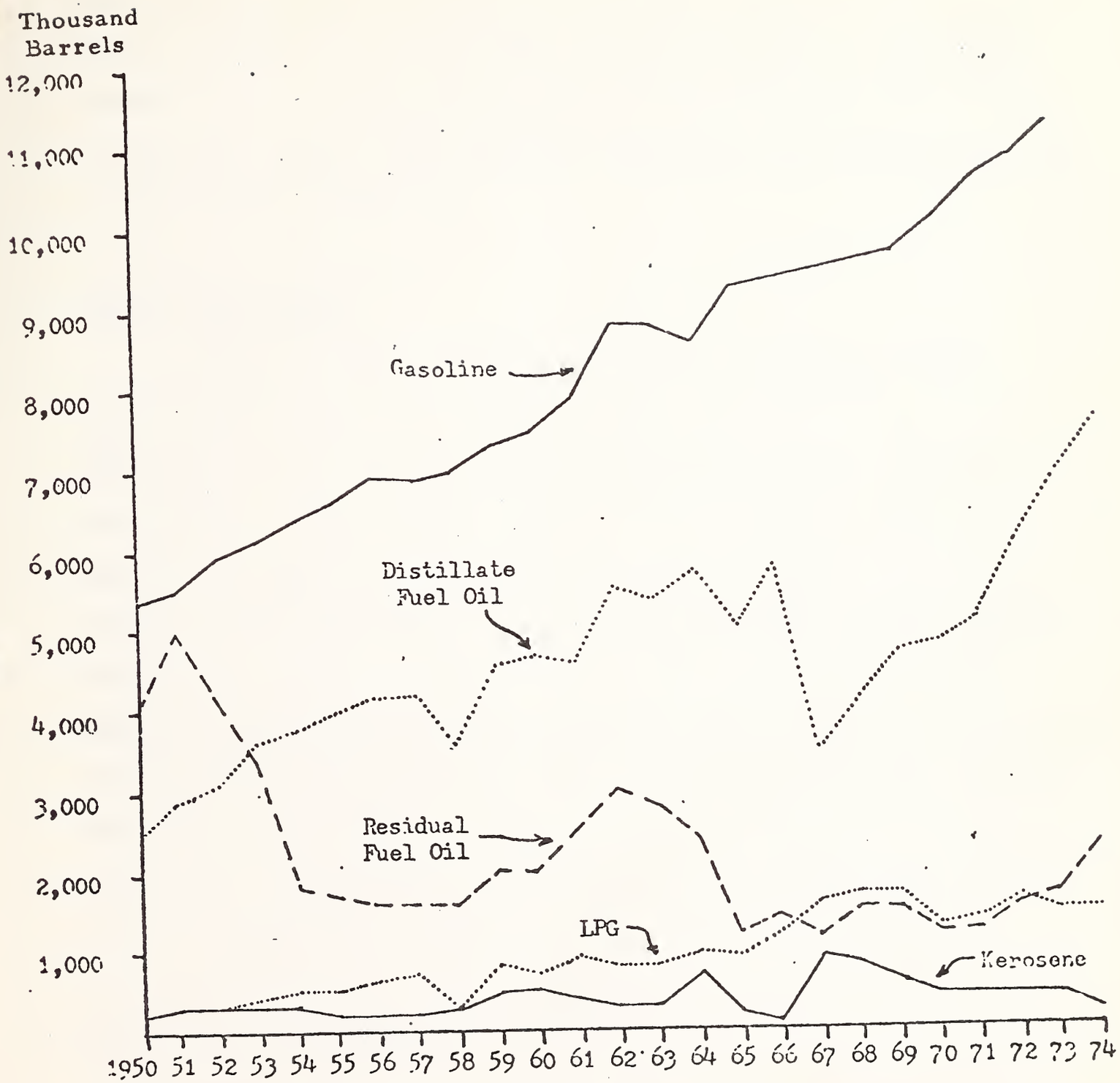


Figure 3

Consumption of Petroleum Products in Montana

Source: U.S. Bureau of Mines

total crude oil refined in Montana as 50,967,000 barrels with 23,037,000 bbls (or 45.2%) coming from Canada, while for the same year Bu Mines reports a total of 43,353,000 bbls being refined with 13,012,000 (or 30%) coming from Canada. MEAC (Montana Energy Advisory Council) is trying to reconcile these differences.

Task 5 - Coal Supply

Listings of major coal deposits in eastern Montana giving the location, quantity and characteristics of the coal in each bed are given in Tables III and IV. Tabe III, issued by the Montana Bureau of Mines and Geology lists a larger number of coal fields than Table IV, which was taken from the Keystone Coal Industry Manual, but Table IV is more descriptive of the fields listed. A map showing the various counties and the coal deposits is given in Figure 4. Discussions with members of the Montana Trade Commision indicated that the coal most likely to be used for the proposed plant is from the S bed. A detailed analysis of coal from this bed is given in Table V. The probable coal cost from this bed was set at $7 a ton. This is based on the $5.00 per ton cost recommended in the Gas Cost Guidelines (C. F. Braun Co. FE-1235-1. Jan. 1976), plus an estimated $1.00 per ton for transportation to the plant site and $1.00 per ton coal severance tax.

Task 6 - Site

The Glasgow Air Force Base was identified as a suitable site for the proposed plant at the meeting of Montana, Dravo and Avco representatives in Pittsburgh on June 2, 1976. A report by the Montana Energy and MHD Research and Development Inst. describing the site in detail was sent to Dravo on June 9, 1976. Although this study was

Table III

MONTANA BUREAU OF MINES AND GEOLOGY

Strippable subbituminous and lignite coal fields, eastern Montana

	Name of field	Coal bed	Est. reserves in millions of tons	Acreage	Average tons/acre	Ash[1]	Sulfur[1]	Btu[1]
1	Decker	Anderson-Dietz 1&2	2,239.99	25,523	87,763	4.0	.40	9,652
2	Deer Creek	Anderson-Dietz 1&2	495.65	14,214	35,397	4.0	.50	9,282
3	Roland	Roland	218.04	12,076	18,055	9.2	.74	8,164
4	Squirrel	Roland	133.41	6,208	21,490	5.5	.29	7,723
5	Kirby	Anderson	216.52	5,655	38,285	4.2	.32	8,328
		Wall	473.69	5,952	79,579			
		Dietz	834.35	17,516	47,630	5.8	.59	8,509
		Canyon	158.53	4,066	38,983	5.8	.24	8,789
6	Canyon	Wall	1,884.25	23,859	78,974	4.6	.30	9,088
		Brewster-Arnold	65.86	2,067	31,859	7.5	.40	8,444
7	Birney	Brewster-Arnold	180.55	6,969	25,905	5.1	.41	9,055
8	Poker Jim Lookout	Anderson-Dietz	872.65	19,609	44,501	5.2	.37	7,925
9	Hanging Woman Cr.	Anderson	1,583.29	30,547	51,830	4.9	.29	8,496
		Dietz	1,120.96	43,654	25,678	5.5	.33	8,078
10	West Moorhead	Anderson	883.74	19,660	44,949	5.3	.36	8,296
		Dietz	397.49	20,416	19,469	4.1	.41	7,990
		Canyon	690.19	22,547	30,611	5.6	.45	8,055
11	Poker Jim O'Dell	Knobloch	373.29	7,890	47,311	5.1	.22	8,846
		Knobloch	564.78	7,187	78,581			
12	Otter Creek	Knobloch	2,075.55	25,791	80,475	4.7	.36	8,468
13	Ashland	Knobloch	2,696.20	27,200	99,125	4.8	.15	8,421
		Sawyer A & C	357.49	20,262	17,643	4.9	.49	7,883
14	Colstrip	Rosebud	1,439.26	33,379	43,118	9.5	.12	8,836
15	Pumpkin Creek	Sawyer	2,426.50	45,695	53,102	7.5	.34	7,438
16	Foster Creek	Knobloch	708.13	27,801	25,470	7.8	.76	7,573
		Terret	460.87	27,462	16,782	5.8	.21	7,770
		Flowers-Goodale	258.90	14,444	17,924	7.8	.51	7,553
17	Broadus	Broadus	739.82	18,429	40,142	7.2	.27	7,437
18	East Moorhead	T	525.21	15,559	33,756	6.2	.57	7,120
19	Diamond Butte	Canyon	418.02	21,363	19,566	4.8	.43	7,330
20	Goodspeed Butte	Cook	628.95	13,446	46,775	10.6	1.63	6,771
21	Fire Gulch	Pawnee & Cook	336.69	8,486	39,674	3.8	.33	7,739
22	Sweeney-Snyder	Terret	326.33	10,921	29,880	9.1	.11	8,175
23	Yager Butte	Elk & Dunning	1,175.86	26,924	43,673	4.8	.33	7,646
		Cook	312.02	14,507	21,507	6.7	.63	7,254
24	Threemile Buttes	Canyon & Ferry	225.40	13,836	16,289	5.5	.94	6,867
25	Sonnette	Pawnee	320.25	8,224	38,940	9.8	.88	6,964
		Cook	362.98	10,470	34,668	8.1	1.23	6,891
26	Home Creek Butte	Canyon & Ferry	217.21	4,851	44,774			
27	Little Pumpkin Creek	Sawyer A&C, D, X, & E	215.83	8,534	25,290			
28	Sand Creek	Knobloch	267.34	5,952	44,915	6.6	.30	7,340
29	Beaver-Liscom	Flowers-Goodale & Terret	135.87	8,851	15,350	8.1	.96	8,102
		Knobloch	491.62	17,075	28,791	7.7	.50	8,027
30	Greenleaf-Miller Creek	Rosebud, Knobloch, and Sawyer	453.71	14,918	30,413	7.5	.71	8,422
31	Pine Hills	Dominy	193.87	6,022	32,191	7.2	.53	7,293
32	Knowlton	Dominy (M & L)	747.51	19,613	38,112	7.1	.41	6,710
		Dominy (U)	120.31	4,448	27,048	5.6	.38	6,615
33	Sarpy Creek	Rosebud McKay	1,500.00	42,373	35,400	6.5	.50	8,600
34	Cheyenne Meadows	Knobloch	1,200.00	13,560	88,500	4.1	.40	8,400
35	Little Wolf	Rosebud-McKay	314.00	7,411	42,370			
36	Jeans Fork		90.00	3,800	23,685			
37	Wolf Mountains		1,922.00	31,000	62,000			
38	Lame Jones	Dominy	150.00	10,593	14,160			6,020
39	Lamesteer	Harmon(?)	35.00	1,978	17,700			6,332
40	Wibaux	C	643.00	18,518	34,720	7.9	.90	6,050
41	Little Beaver	C	134.00	8,445	15,865			
42	Four Buttes	C	91.00	5,180	17,570			6,149
43	Hodges		10.00	807	12,390			
44	Griffith Creek		10.00	568	17,700			

Table III Continued

MONTANA BUREAU OF MINES AND GEOLOGY

Strippable subbituminous and lignite coal fields, eastern Montana

	Name of field	Coal bed	Est. reserves in millions of tons	Acreage	Average tons/acre	Ash[1]	Sulfur[1]	Btu[1]
45	Smith-Dry Creek	G	150.00	8,475	17,700			
46	O'Brian-Alkalie Creek		150.00	8,475	17,700			
47	Breezy Flat	Pust	200.00	7,062	30,090	6.7	.50	6,660
48	Burns Creek	Pust	200.00	7,062	30,090			
49	N.F.Thirteen Mile Creek	Pust	225.00	5,085	44,250			6,880
50	Fox Lake	Pust	46.00	2,166	21,240			6,880
51	Lane	Lane	561.00	44,582	12,390			7,150
52	Carroll	Carroll	345.00	29,780	11,584	5.5	.30	7,400
53	Redwater River	S	642.00	24,181	26,550	6.1	.40	7,400
54	Weldon-Timber Creek	S	724.00	25,565	28,320			7,660
55	Fort Kipp	Ft. Kipp-Ft. Peck	331.00	14,500	22,830	4.6	.20	6,110
56	Lanark	Lanark	100.00	3,531	12,390	6.3	.40	6,853
57	Medicine Lake		58.00	3,740	15,510	7.2	1.00	6,870
58	Reserve		246.00	18,231	13,495	7.6	.40	6,599
59	Coal Ridge	Coal Ridge	150.00	19,200	17,700	7.5	.40	5,830
60	Carpenter Creek	Carpenter	50.00	3,211	14,015	6.5	.40	9,270
61	Charter	Mammoth	60.00	3,210	17,700	6.0	.90	10,190
62	Little Sheep Mtn.	A&C	200.00	10,272	19,470			
		TOTAL	42,561.93	1,152,640				

[1] "As received" basis (where more than one sample available, figures given are average figures).

By Robert E. Matson

Table IV

Strippable subbituminous and lignite coal fields, eastern Montana.

	Name of Field	County	Coal Bed	Tickness in Feet	Estimated Reserves in Millions of Tons (R-rough; F-fair; G-good)	Typical analyses (as received basis) Moisture	Volatile matter	Fixed carbon	Ash	Sulfur	Hydrogen	Carbon	Nitrogen	Oxygen	Btu
1.	Carbert	Daniels	D & C	8	150 R	41.3	23.0	26.4	9.2	0.5	....	....	....	....	5,675
2.	Poplar River	Daniels	D	11	75 R	....	....	....	....	....	....	....	....	....	.....
3.	Coal Ridge	Sheridan	Coal Ridge	10	600 F	40.4	24.5	27.6	7.5	0.4	6.9	35.2	0.6	49.4	5,830
4.	Reserve	Sheridan		7	246 F	38.5	24.8	29.0	7.6	8.4	....	....	....	....	6,599
5.	Medicine Lake	Sheridan		9	58 F	37.0	26.3	29.5	7.2	1.0	....	....	....	....	6,870
6.	Fort Kipp	Roosevelt	Fort Peck Fort Kipp	5.3 8.5	278 G	42.8	25.7	26.9	4.6	0.2	7.2	36.2	0.6	51.2	6,110 .....
7.	Lanark	Roosevelt	Lanark Archer	....	100 G	38.1	25.5	32.3	4.1	1.2	....	....	....	....	6,724
8.	Weldon-Timber Ck.	McCone	S	8-20	724 G	30.5	27.7	35.9	5.9	0.6	....	....	....	....	7,660
9.	Redwater River	McCone-Richland	S	9-21	642 G	31.7	27.5	35.0	6.1	0.4	6.4	41.1	0.8	44.6	7,400
10.	Fox Lake	Richland	Pust	7-17	46 F	38.3	25.4	30.3	6.0	0.5	....	....	....	....	6,880
11.	N.F. 13-Mile Ck.	Dawson	Pust	10-43	225 F	38.3	25.4	30.3	6.0	0.5	....	....	....	....	6,880
12.	Burns Creek	Dawson	Pust	....	200 R	....	....	....	....	....	....	....	....	....	.....
13.	Breezy Flat	Richland-Dawson	Pust	9-25	200 F	38.6	25.1	29.3	7.0	0.9	6.7	39.5	0.6	45.3	6,520
14.	O'Brien-Alkalie Ck.	Richland	F, S, and H	....	150 R	....	....	....	....	....	....	....	....	....	.....
15.	Four Buttes-Smith Creek	Wibaux	G and C	5-20	400 R	37.9	26.4	26.1	9.6	1.0	....	....	....	....	6,140
16.	Griffith Creek Hodges	Dawson-Wibaux	A	10	90 R	....	....	....	....	....	....	....	....	....	.....
17.	Little Beaver	Wibaux	C	10-15	250 R	....	....	....	....	....	....	....	....	....	.....
18.	Beach-Wibaux	Wibaux	C	5-40	1,204 F	41.0	24.8	26.3	7.9	0.9	....	....	....	....	6,050
19.	Lamesteer	Wibaux	Harmon (?)	10	35 F	....	....	....	....	....	....	....	....	....	.....
20.	Pine Hills	Custer	Dominy E	6-19	100 G	30.8	27.3	33.7	8.2	0.6	6.2	43.9	0.7	40.4	7,220
21.	Lame-Jones	Fallon-Carter		6-10	150 R	38.7	27.0	25.1	9.2	0.3	....	....	....	....	6,020
*22.	Sweeney-Snyder	Rosebud	Terret	....	....	24.63	27.79	38.44	9.14	1.12	....	....	....	34.2	8,200
23.	Colstrip Castle Rock Arnells Creek	Rosebud	Rosebud, McKay	20-26	1,300 G	23.1	29.9	41.5	5.5	0.7	6.3	54.9	0.8	31.8	9,500
24.	Greenleaf Miller Creek	Rosebud	Rosebud Knoblock	4-12 3-21	....	....	....	....	....	....	....	....	....	....	....
*25.	Foster-Pumpkin Creek	Custer-Powder River	Knoblock-Terret Flowers-Goodale	....	....	31.6	26.8	35.4	6.2	0.2	6.3	46.2	0.7	40.5	7,630
*26.	Sand Creek	Custer-Powder River	Knoblock	....	....	31.1	27.8	32.8	8.3	0.3	6.5	43.1	0.6	41.2	7,220
27.	Cook Creek	Powder River	Sawyer	8-12	18 G	....	....	....	....	....	....	....	....	....	.....
28.	Home Creek	Powder River	Sawyer	8-9	41 G	....	....	....	....	....	....	....	....	....	.....
29.	Poker Jim O'Dell Creek	Rosebud	Knoblock	25	250 F	....	....	....	....	....	....	....	....	....	.....
30.	Birney	Rosebud	Knoblock Brewster-Arnold	40 20	200 R	....	....	....	....	....	....	....	....	....	....
31.	Otter Creek	Powder River	Knoblock	20-47	1,100 G	26.6	29.6	38.6	5.2	0.2	6.4	52.0	0.8	35.4	8,740
32.	Sonnette	Powder River	Pawnee	20	206 G	32.0	29.5	32.5	6.0	0.2	6.7	45.4	0.8	40.9	7,650
33.	Canyon Creek	Rosebud	Wall	30-64	80 R	....	....	....	....	....	....	....	....	....	.....
34.	Kirby	Big Horn	Anderson & Smith	20-30 20-30	200 R	....	....	....	....	....	....	....	....	....	....
35.	Bluffer	Big Horn	Anderson & Smith	....	80 R	....	....	....	....	....	....	....	....	....	.....
36.	Decker	Big Horn	Deitz	20-80	1,020 G	21.0	39.0	41.0	4.0	0.4	....	....	....	....	9,720
37.	Hanging Woman Creek	Big Horn	Deitz Anderson Smith	12 20-30 20-38	500 R ..... 800 R	....	....	....	....	....	....	....	....	....	....
	Roland	Big Horn	Roland	6-15	300 R		....	....	....	....	....	....	....		.....
38.	Moorhead	Powder River	Canyon Deitz Anderson	17-25 6-11 14-30	1,500 F	23.4	32.3	40.4	3.9	0.2	6.1	52.7	1.1	35.6	8,920
39.	Upper Cache Ck.	Powder River	Pawnee	20	40 G	32.0	29.5	32.5	6.0	0.2	6.7	45.4	0.8	40.9	7,650
40.	Lower Cache Ck.	Powder River	Broadus	12	10 G	33.5	28.3	32.2	6.0	0.4				....	7,290
41.	Fire Creek	Powder River	Pawnee	16-20	10 R				....						
*42.	Broadus	Powder River	Broadus	....	....	28.95	28.86	35.29	6.90	0.24	6.4	45.7	0.7	40.7	7,550
43.	Bull Mountain	Musselshell	Carpenter Creek	....	50 F	....	....	....	....	....	....	....	....	....	.....

	13,658
*Coal thickness and individual tonnage data cannot be released (Sweeney-Snyder, Foster-Pumpkin Creek, Sand Creek, Broadus).....	3,350
TOTAL	17,008

Montana

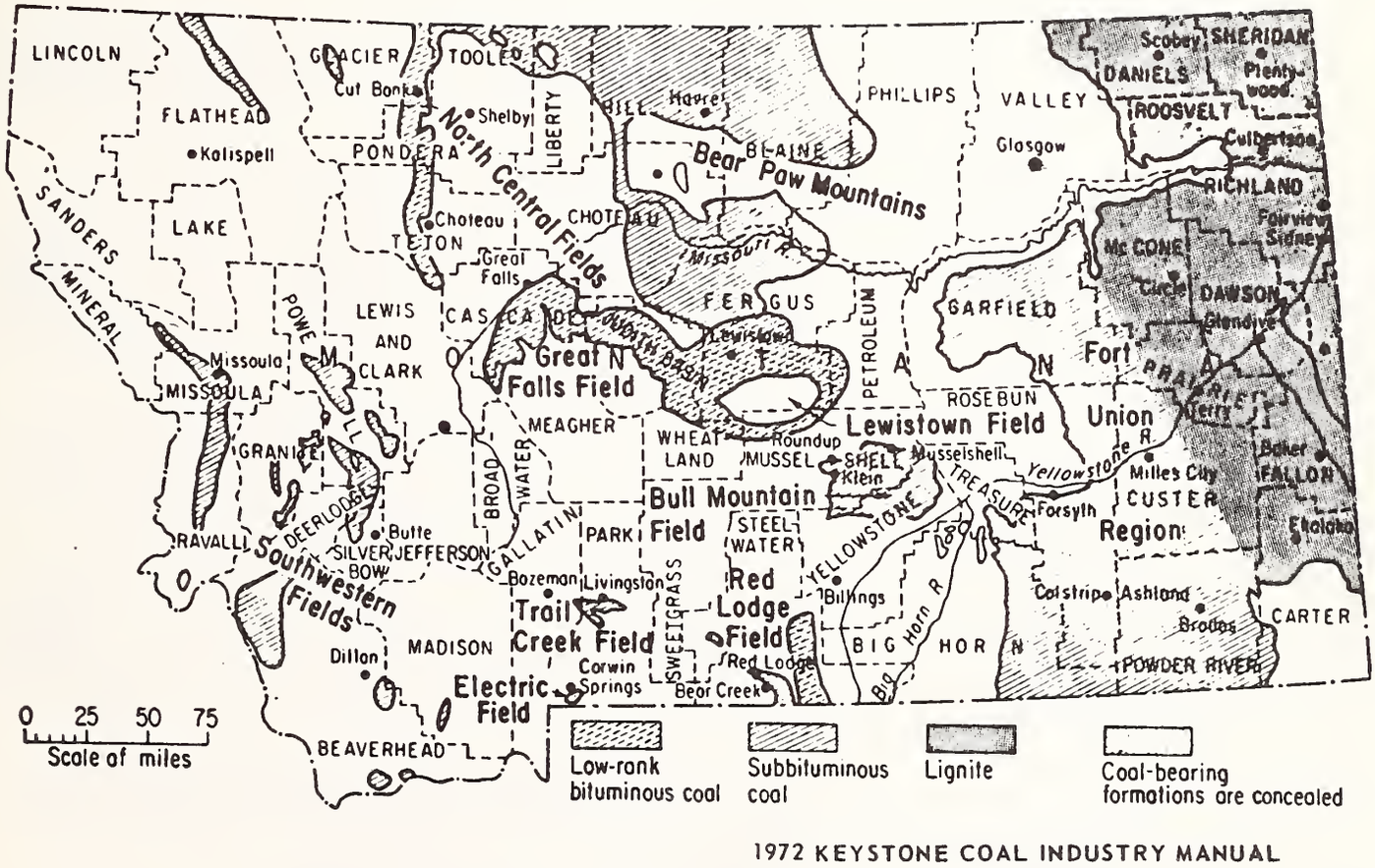


Figure 4. Map of Montana showing Counties and Location of Coal Fields

Table V

Coal Quality "S" Coal Bed
83 Samples
3 to 4 Ft. Increments

Proximate Analysis (As Received)

	Moisture	Ash	Volatile Matter	Fixed Carbon	BTU	Sulfur
High	40.58	11.47	28.68	35.64	7428	1.34
Low	30.74	4.76	24.70	27.68	6242	0.20
Average	34.85	6.86	26.60	31.67	6928	0.54

Ultimate Analysis (As Received)

	%C	%H	%N	%Cl	%S	%O
High	44.36	2.94	0.70	0.01	1.34	13.81
Low	39.72	2.47	0.50	0.00	0.20	10.98
Average	41.46	2.67	0.60	0.01	0.54	12.57

Sulfur Forms (As Received)

	Pyritic	Sulphate	Organic	Total
High	1.36	0.07	0.93	2.11
Low	0.01	0.00	0.23	0.31
Average	0.27	0.01	0.23	0.51

Ash Fusion (Reducing Condition)

	Initial Deformation	Softening (H=W)	Softening (H=½W)	Fluid
High	2420	2440	2470	2490
Low	2190	2200	2220	2250
Average	2320	2350	2370	2390

Ash Fusion (Oxidizing Conditions)

	Initial Deformation	Softening (H=W	Softening (H=½W)	Fluid
High	2460	2520	2530	2560
Low	2260	2270	2280	2290
Average	2400	2420	2440	2460

directed toward the use of the base as an Energy Center the data developed is equally applicable to a coal gasification center.

The report states that the Glasgow Air Force Base is within 80 miles of two large coal deposits, Weldon-Timber Creek and Redwater, having combined indicated reserves of over 1 billion tons of coal. The water flow of the nearby Missouri River at the Ft. Peck Reservoir and Dam is 6.8 million acre-feet per year which should be much more than adequate for a coal gasification plant which should require at most 20,000 acre-feet per year. The infrastructure of the Air Force Base and the town of Glasgow should accomodate the gasification plant work force without difficulty. In fact many of the facilities have not been used since the drastic reduction in air base operations in 1968. Consequently, new uses for the facilities and new oportunity for employment should be welcome.

Task 7-8-9

These tasks relate to gathering information pertinent to the financial planning of the Montana gasification project. The exploration of opportunities in federal financial assistance, liaison with financial advisors concerning financial factors used as a basis for economic comparisons, and the collection of data from both Montana and federal sources are included.

In response to Task 7, the exploration of opportunities in federal programs, Avco participated in a meeting with ERDA officials to make them aware of the activities of Montana's Task Force on Coal Gasification and to identify areas of common interest. ERDA

representatives present at the meeting include: Mr. George Rial, Division Director of ERDA's Demonstration Plant Program, Mr. William McCormack, Director of ERDA's Commercialization Program, and Mr. Wesley Barnes and Steven Webb, responsible for ERDA's liaison with congress. The initial meeting was held in the office of Mr. J. S. Kimmitt, Secretary of the Majority of the Senate with follow-up meetings being held in offices of various ERDA officials (S. Mournighan, W. Harmon, S. Schneider). Telephone conversations with Mr. Neal Cochran, Senior Staff Engineer at ERDA also contributed to information developed on this task. A detailed account of this series of meetings and telephone conversations was given in Avco's memo of July 1, 1976. (R. E. Gannon to H. M. Jamison). In essence, ERDA's official position as stated by Rial and McCormack and supported by the other ERDA representatives, is that there was little or no opportunities for "newcomers" to the demonstration plant program and that money for the Synthetic Fuels Loan program would probably only support two projects and that there already are four candidate projects seeking the loans.

Although initially discouraged by the position taken by ERDA, we were somewhat encouraged by the general dissatisfaction with ERDA's awards for demonstration plant studies. We therefore contacted some of the so-called "losers" of the demonstration plant study procurement to explore their possible involvement with Montana in proposing extensions to ERDA's Demo. program. IGT and Texaco were thus contacted. Additionally, Consolidation Coal Co. who have the CO_2 Acceptor process ready for demonstration and the Ralph M. Parsons Co. who have been

designing various gas/oil demos were also contacted. The detail of these discussions were described in Avco's Memo of July 27, 1976 (R. E. Gannon to H. M. Jamison). As a result of the initial discussions, representatives of IGT, Consolidation Coal, and Parsons have been in contact with representatives of the Montana Trade Commission to explore cooperative ventures and necessary commitments of all parties involved.

Later in pursuing opportunities for Montana participation in federally funded programs, a series of telephone calls and meetings were held with C. Lowell Miller, Program Manager for ERDA's pilot plant program. The prime purpose of the meetings was to explore ways in which we could cooperate with ERDA in the construction of a nominal 85 mm SCFD plant in Montana in order to demonstrate the technology of either the Hygas or CO_2 Acceptor processes at a size larger than the current pilot plants. After the preliminary calls and meetings, a larger meeting was arranged for September 29, 1976, at ERDA. In addition to representatives of the Montana Trade Commission and Avco attendees included Mr. Dave Brown of Senator Mansfield's office and the following ERDA personnel: Mr. D. Webb, congressional liaison, Mr. Roland Beck, acting Division Director, Coal Conversion and Utilization, Dr. L. Topper, Division of Commercialization and Dr. C. Lowell Miller, Division of Coal Conversion and Utilization. The tangible result of the meeting was a recommendation by ERDA representatives for Montana to submit an unsolicited proposal to ERDA describing Montana's current program and projected plan to build and operate a coal gasification plant at the Glasgow Air Force Base. This recommendation was taken under advisement by the Montana contingent.

For the purpose of assisting Dravo in establishing a tentative financial plan for the proposed plant to serve as a basis for economic evaluation (Task 8) Avco, after discussion with financial advisors at Dillon Read, Inc. concurs with the follwoing set of factors if utility financing is used:

Debt/Equity Ratio	- 75/25
Loan Interest	- 9%
Return on Investment	- 15%
Federal Income Tax	- 48%
Plant Life	- 20 years
Depreciation	- Straight Line

If on the other hand Municipal bonds are issued, a modified financial plan is needed. Mr. Fenn Putnam, of Dillon Read calculated the following factors:

1. For 6%, 20-year level debt payment bonds, including interest during construction, with reinvestment of unused funds at 5-1/2%, a cost of money factor of 1.2852 should be applied. i.e. for a $300,000,000 project a bond issue of $385,576,000 is needed.
2. For an 8% bond issue (which may be more realistic if the coal severence tax cannot be used as security for the bond) a factor of 1.4505 should be applied. In this case a bond issue of $435,000,000 would be required for a $300,000,000 project.

In regards to Task 9, which directs Avco to assist Dravo in obtaining information from the State of Montana and the federal government, Avco obtained most of the information reported under Tasks 1 through 6 from various Montana agencies and much of the information given under Task 7 from representatives of the federal government. Additionally Avco procurred a copy of a "Memo of Understanding" (MOU) between ERDA and the State of Arizona. This is part of ERDA's states cooperation program. The value of such an MOU has not been demonstrated yet, but on the basis that it might be helpful in extending ERDA's demonstration plant program, Montana's interest in establishing a cooperative program with ERDA has been communicated to the federal government in a letter from Governor Judge to Dr. R.C. Seamans Jr., ERDA Administrator.

Acknowledgement

The contributions of data to this report by Mr. J. A. Kissner of the Montana Trade Commission and Mr. J. L. Magner of Avco Montana Energy Systems is gratefully acknowledged.

APPENDIX C

LURGI

APPENDIX C

TABLE OF CONTENTS

SECTION I: INTRODUCTION

American Lurgi Corporation is pleased to submit to the Montana International Trade Commission, Study No. KGD-00-0791, dated June 1, 1976, evaluating the feasibility of using Lurgi technology to produce NH_3 synthesis gas and SNG from Montana Lignite coal. The proposed plant is a combination of Lurgi coal gasification and gas and gas liquor treatment plants utilizing 18 operating gasifiers and two spares. The plant will produce 150 MMSCFD of SNG with a heating value of 957 BTU/scf and 89 MMSCFD of NH_3 synthesis gas which is equivalent to 1000 TPD of ammonia. The coal consumption will be 17,551 TPD. (graded as received).

The information presented in this study is confidential and shall not be disclosed to third parties without the express written consent of American Lurgi Corporation.

1.0 Scope of Work

The scope of this study includes process calculations and process descriptions for a coal gasification plant consisting of the following Lurgi Process Units:

- Coal Gasification
- Shift Conversion
- Gas Cooling
- Rectisol
- Liquid Nitrogen Wash
- Methanation
- Gas Liquor Separation
- Chemie Linz - Lurgi Anhydrous Ammonia Plant
- Phenosolvan

Areas not included within the scope of this study are:

- Coal Handling and Screening Facilities
- Ash Disposal System
- NH_3 Synthesis
- Sulfur Recovery Plant
- Boiler Feed Water Treatment Facilities
- Cooling Tower
- B.O.D. Plant
- Oxygen Plant

Distribution Systems for Cooling Water, Boiler Feed Water, Steam or Plant Air

Storage or Product Gas Distribution Facilities

Buildings and Offices

SECTION II: BASIS OF STUDY

1.1 General

This study is based on processing North Dakota Lignite having properties as shown on Table 2.1, which is very similar to the Montana Lignite proposed for use in this plant. This type of coal is an excellent feedstock for Lurgi gasification and has been successfully tested on a commercial scale in a Lurgi gasifier at Sasolburg, South Africa, during September, 1974.

The ultimate coal gasification plant is to be located in Montana and shall be a self-supporting facility, which can be designed to be totally compatible with the prospective abandoned SAC base which is presently under consideration as a plant site.

The use of such a site has many advantages as most of the infra-structure is already developed. More specific comments on the advisability of constructing a plant on this site will be offered by your selected contractor.

The design of the plant is based on commercially proven processes and equipment and will provide a dual product which can be utilized to fulfill the needs of the people of the State of Montana. The plant will produce SNG to provide fuel for domestic and industrial purposes and ammonia for the State's agricultural requirements.

2.0 Design Criteria

2.1 Coal Feed Stock

The feed stock is Montana Lignite coal having the following properties:

Proximate Analysis

	As Received	DAF
Moisture	35.02 wt. %	-
Ash	6.86 wt. %	-
Volatiles	26.45 wt. %	45.51 wt. %
Fixed Carbon	31.67 wt. %	54.49 wt. %
TOTAL	100.0 wt. %	100.0 wt. %

Ultimate Analysis

Carbon	71.68 wt. %
Hydrogen	4.59 wt. %
Nitrogen	1.03 wt. %
Combustible Sulfur	0.93 wt. %
Chlorine	0.02 wt. %
Oxygen	21.75 wt. %
TOTAL	100.0 wt. %

Fischer Assay (at 520°C)

Carbonization Liquor	7.50 wt. %
Tar	7.79 wt. %
Coke	68.11 wt. %
Gas & Losses	16.60 wt. %
TOTAL	100.0 wt. %

2.2 Feed Stocks and Utilities Requirements

The utilities and feed stocks required by the plant will be approximately as follows:

Coal for gasification (graded, moisture and ash included)	1,462,610 lb/hr
Coal for steam generation (moisture and ash included)	101,500 lb/hr
Oxygen (100%)	3.482 MMSCF/hr
Boiler Feed Water (delivered treated at 68°F)	2,283 gpm
Recirculated Cooling Water (temperature range 112°F-80°F)	130,295 gpm
Power	86,125 kwh

2.3 Offsite Requirements

In addition to the facilities required to supply the utilities and feed stocks listed in Paragraph 2.2, the following facilities will be required to handle the plant off streams:

- Coal handling facilities capable of delivering 17,551 TPD of coal to the gasifier graded as received (1/8" - 2");
- Ash handling facilities capable of transporting 105,580 lb/hr of ash to an offiste disposal area;
- Sulfur recovery facilities capable of treating 170,430 scfm of off gas with 0.79 vol. % H_2S.

2.4 Miscellaneous Design Criteria

The overall plant complex can be designed to have maximum reliability to minimize the possibility of interruption in gas production. To achieve this, spare equipment at critical points has to be incorporated.

The design of the plant is based on commercially proven processes and equipment and, from a history of actual performance of Lurgi designed plants, will achieve an overall service factor of 92% annually.

1.0 Preface

This section describes the individual process sections and their integration to make up the complete plant. The block flow diagram at the end of this section should be referred to in conjunction with the process description.

Stream flow rates and compositions for the major process streams indicated in the Block Flow Diagram are presented in Section III, Paragraph 11. For convenience, the gas compositions of major process streams are also given in the text.

The utilities requirements for the individual process areas are indicated in the Block Flow Diagram. Arrows pointing toward the process block indicate that the utility is consumed by the process. Arrows pointing away from the process block indicate that the utility is generated by the process. In this balance, no sharing of utilities among the various processes has been considered.

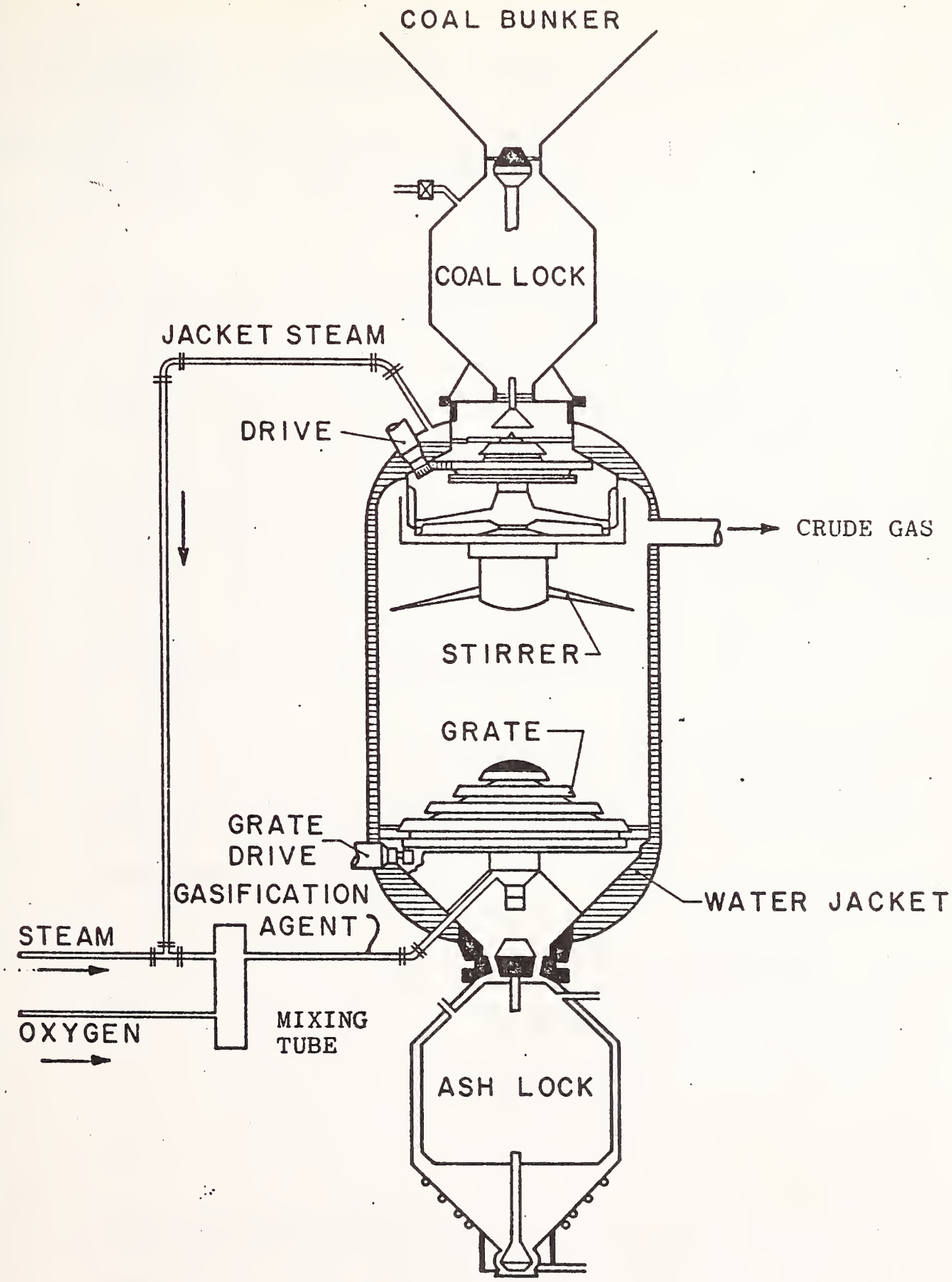
The approximate space requirements of the overall plant are shown in Drawing No. P-309-2.

2.0 Coal Gasification

17551

In the Coal Gasification Section, 1,462,610 lb/hr of graded coal are gasified in eighteen gasifiers to produce a crude fuel gas. A portion of the sensible heat is recovered from the gas in eighteen gasification waste heat boilers and utilized to produce 100 psia steam which is available for use elsewhere in the Plant. A sketch of a typical gasifier is shown in Figure 1.

Graded coal, Stream 1, is fed at atmospheric pressure into a Coal Bunker which is located at the top of the gasifier assembly. From the bunker the coal is charged, as required, into a Coal Lock, which is then pressurized with crude gas. Once under pressure the coal can then be introduced into the top of the Gasifier for gasification. When the Coal Lock is empty, it is sealed off from the Gasifier and depressurized. The expanded lock gas, Stream 3, can either be used to repressurize the Coal Lock or it can be cleaned and incinerated. When the Coal Lock has returned to atmospheric pressure, it can once again be charged with coal. One complete charging, discharging, depressurizing cycle takes about 30 minutes. The charging and discharging ports are sealed by automatically controlled hydrualic valves.



LURGI

LURGI PRESSURE GASIFIER

FIGURE 1

The Gasifier is a double shell pressure vessel operating at an internal pressure of about 440 psia. The inner shell forms a vessel within which the gasification reactions take place. The annulus between the two shells serves as a water jacket to provide cooling for the wall of the inner vessel. Steam which is produced in the jacket by the transfer of reaction heat through the inner shell is used in the gasifier as described below.

The coal enters the top of the Gasifier and gravitates downward as a slowly moving bed through four basic zones described generally as:

Preheating and Drying
Devolatilization
Gasification
Combustion

Preheating and drying are achieved in the top section of the Gasifier as the crude gas passes upward through the bed. The preheated coal then enters the Devolatilization zone where carbonization liquor and tars, as well as some gas, are distilled off. Next, the coal enters the Gasification zone where carbon and steam (which has been introduced into the bottom of the Gasifier mixed with oxygen) undergo a series of

complex reactions to form the main components (H_2, CO, CH_4, CO_2, and steam) of the final fuel gas. The heat required to support the overall gasification reaction is finally generated by combusting the remaining coke with oxygen in a narrow Combustion zone located just above a layer of ash, which sits on a rotating grate. The remaining ash is continuously transferred to the bottom of the Gasifier by the rotating grate. The rate of ash removal is regulated according to the rate at which the coal is gasified, which is in turn, controlled by the injection rate of gasification agent into the bottom of the gasifier.

Oxygen, Stream 2, and superheated steam are mixed in the required proportions in a Mixing Tube. The mixture is introduced into the bottom of the Gasifier below the ash grate and is further heated by the high temperature ash. The oxygen is completely consumed in the oxidation reaction. In addition to providing hydrogen for the gasification reactions, the steam acts as a coolant to maintain the Combustion zone temperature below the melting point of the ash and thereby prevents slagging or the formations of clinkers.

A portion of the required gasification steam is generated in the water jacket as noted above, and passes via a knock-out drum to the Mixing Tube.

The high temperature reaction gases and unreacted steam move upward, and exchange heat with the coal bed. This counter-current flow in the Gasifier promotes natural zones for the gasification reactions and maximizes the efficiency of the process by utilizing the sensible heat of the gas for devolatilization, drying, and preheating.

The ash, Stream 5, falls from the bottom of the Gasifier into an Ash Lock and is finally discharged to a suitable ash handling system which transports it to an ash disposal point. Operation of the Ash Lock is similar to the operation of the Coal Lock. The hot crude gas, Stream 4, leaves the top of the Gasifier and is immediately washed and quenched in a Wash Cooler with recycled gas liquor from the Gasifier Waste Heat Boiler. This scrubs out any coal dust which might be carried over from the Gasifier and condenses some of the heavy tars which are a product of the gasification reactions.

The gaseous composition of Stream 4 is summarized as:

Component	lbmoles/hr	Mole %
CO_2	23042.3	32.65
H_2S	211.7	0.30
C_2H_4	317.6	0.45
CO	11510.6	16.31
H_2	27128.5	38.44
CH_4	7671.3	10.87
C_2H_6	479.9	0.68
N_2	211.7	0.30
Total Dry Gas	70573.6	100.0
H_2O	75202.9	

The two phase mixture of saturated crude gas and gas liquor from the Wash Cooler enters the Gasifier Waste Heat Boiler where the sensible heat of the gas is used to generate approximately 600,000 lb/hr of saturated 100 psia steam. This steam is available for use elsewhere in the plant.

The partially cooled crude gas, Stream 6, leaves the gasification section and enters the waste heat boilers in the shift conversion section.

The gaseous composition of Stream 6 is summarized as:

Component	lbmoles/hr.	Mole %
CO_2	23042.3	32.65
H_2S	211.7	0.30
C_2H_4	317.6	0.45
CO	11510.6	16.31
H_2	27128.5	38.44
CH_4	7671.3	10.87
C_2H_6	479.9	0.68
N_2	211.7	0.30
Total Dry Gas	70573.6	100.00
H_2O	46814.0	

The net gas liquor which condenses in the Gasifier Waste Heat Boiler, Stream 7, is fed to the Gas Liquor Separation Section.

3.0 Shift Conversion

The gas produced in the gasifier has a somewhat lower H_2/CO ratio than that required to produce NH_3 Syngas and SNG on an efficient basis. Therefore, the purpose of shift conversion is to produce hydrogen by reacting carbon monoxide and steam over a suitable catalyst. This is represented by the following chemical equation:

$$CO + H_2O = CO_2 + H_2$$

Before entering the shift conversion reactors, the temperature of the crude gas is adjusted in the shift waste heat boiler by generating saturated 100 psia steam. Condensate and some tar, Stream 8, from this heat exchanger flows directly to the Gas Liquor Separation unit. Approximately 58% of the total

crude gas is subjected to shift conversion with the balance bypassed directly to the gas cooling unit. The proportions of these two gas streams are adjusted to achieve the desired H_2:CO ratio for the NH_3 and CH_4 synthesis. The converted gas from this area is split into streams going to NH_3 synthesis and methanation. Both streams are cooled so as to remove hydrocarbon by-products and unreacted steam. The gas flows to and from shift conversion are represented by Stream 9 and Stream 10 respectively.

	Stream 9		Stream 10	
Component	lbmoles/hr	Mole %	lbmoles/hr	Mole %
CO_2	13409.6	32.65	17970.1	39.39
H_2S	123.2	0.30	123.2	0.27
C_2H_4	184.8	0.45	184.8	0.40
CO	6698.7	16.31	2138.2	4.69
H_2	15787.7	38.44	20348.2	44.59
CH_4	4464.4	10.87	4464.4	9.78
C_2H_6	279.3	0.68	279.3	0.61
N_2	123.2	0.30	123.2	0.27
Total Dry Gas	41070.9	100.00	45631.4	100.00
H_2O	20336.0		15775.5	

4.0 Gas Cooling

The Gas Cooling Section cools two segregated streams in parallel processing trains. One train cools the fraction of the shifted gas, Stream 11, from which ammonia will be synthesized. The second train cools the combined shift bypass gas, Stream 15, and the rest of the shifted gas, Stream 14. This combined flow, Stream 16, will be processed to SNG. These streams are summarized as follows:

crude gas is subjected to shift conversion with the balance bypassed directly to the gas cooling unit. The proportions of these two gas streams are adjusted to achieve the desired H_2:CO ratio for the NH_3 and CH_4 synthesis. The converted gas from this area is split into streams going to NH_3 synthesis and methanation. Both streams are cooled so as to remove hydrocarbon by-products and unreacted steam. The gas flows to and from shift conversion are represented by Stream 9 and Stream 10 respectively.

	Stream 9		Stream 10	
Component	lbmoles/hr	Mole %	lbmoles/hr	Mole %
CO_2	13409.6	32.65	17970.1	39.39
H_2S	123.2	0.30	123.2	0.27
C_2H_4	184.8	0.45	184.8	0.40
CO	6698.7	16.31	2138.2	4.69
H_2	15787.7	38.44	20348.2	44.59
CH_4	4464.4	10.87	4464.4	9.78
C_2H_6	279.3	0.68	279.3	0.61
N_2	123.2	0.30	123.2	0.27
Total Dry Gas	41070.9	100.00	45631.4	100.00
H_2O	20336.0		15775.5	

4.0 Gas Cooling

The **Gas Cooling** Section cools two segregated streams in parallel processing trains. One train cools the fraction of the shifted gas, Stream 11, from which ammonia will be synthesized. The second train cools the combined shift bypass gas, Stream 15, and the rest of the shifted gas, Stream 14. This combined flow, Stream 16, will be processed to SNG. These streams are summarized as follows:

	Stream 11		Stream 14	
Component	lbmole/hr	Mole %	lbmole/hr	Mole %
CO_2	6606.1	39.39	11364.0	39.39
H_2S	45.3	0.27	77.9	0.27
C_2H_4	67.9	0.40	116.9	0.40
CO	786.0	4.69	1352.2	4.69
H_2	7480.4	44.59	12867.8	44.59
CH_4	1641.2	9.78	2823.2	9.78
C_2H_6	102.7	0.61	176.6	0.61
N_2	45.3	0.27	77.9	0.27
Total Dry Gas	16774.9	100.00	28856.5	100.00
H_2O	5799.3		9974.2	

	Stream 15		Stream 16	
Component	lbmole/hr	Mole %	lbmole/hr	Mole %
CO_2	9632.7	32.65	20996.7	35.97
H_2S	88.5	0.30	166.4	0.29
C_2H_4	132.8	0.45	249.7	0.43
CO	4811.9	16.31	6164.1	10.56
H_2	11340.8	38.44	24208.6	41.48
CH_4	3206.9	10.87	6030.1	10.33
C_2H_6	200.6	0.68	377.2	0.65
N_2	88.5	0.30	166.4	0.29
Total Dry Gas	29502.7	100.00	58359.2	100.00
H_2O	14608.0		24584.2	

The Gas Cooling unit is designed for efficient recovery of waste heat by minimizing the quantity of heat exchange to air and cooling water. In addition to heat recovery, the purpose of the Gas Cooling unit is to remove the heavier hydrocarbons and unreacted steam before low temperature purification. Heat exchange in the first two stages of gas cooling is used to produce 70 psia and 30 psia saturated steam.

Further heat removal is accomplished by exchange with boiler feedwater for preheating purposes and finally by exchange with cooling water.

A considerable quantity of hot gas liquor, tar, and oil is condensed from the crude gas as it cools. These liquids are routed to the Gas Liquor Separation Section.

The cooled gas streams are Stream 12, which goes to NH_3 synthesis and Stream 17, which goes to Methanation. These streams are summarized as follows:

	Stream 12		Stream 17	
Component	lbmole/hr	Mole %	lbmole/hr	Mole %
CO_2	6606.1	39.39	20996.7	35.97
H_2S	45.3	0.27	166.4	0.29
C_2H_4	67.9	0.40	249.7	0.43
CO	786.0	4.69	6164.1	1(.56
H_2	7480.4	44.59	24208.6	41.48
CH_4	1641.2	9.78	6030.1	10.33
C_2H_6	102.7	0.61	377.2	0.65
N_2	45.3	0.27	166.4	0.29
Total Dry Gas	16774.9	100.00	58359.2	100.00
H_2O	23.0		80.0	

5.0 Rectisol

The function of the Rectisol unit is to purify the two gas streams by the removal of sulfur compounds to the level of 0.1 ppmv total sulfur, removal of naphtha and hydrogen cyanide and the reduction of the carbon dioxide concentration to a level compatible with the NH_3 synthesis and methanation process steps.

The economics of a wash process depends mainly on the properties of the solvent.

The Rectisol process operates at low temperatures and uses methanol as the solvent. In this temperature range, methanol has rather favorable properties regarding the absorption of CO_2, H_2S, and COS as well as other gas impurities. The specific characteristics of methanol which make it particularly suitable as a physical solvent are:

High solubility for CO_2, H_2S, and COS

- This keeps the solvent circulation rate low and provides for optimum economics of Rectisol plants when the impurities in the raw gas are present in high concentration.

Low solubility for H_2, CO, and CH_4

-This keeps gas losses at a very low level.

Low vapor pressure under process conditions

-Solvent losses are very low.

High solubility for water

-Rectisol plants can at the same time be used for gas dehydration.

Low viscosity, even at low temperatures

-This characteristic ensures good heat and mass transfer, even at temperatures just above the freezing point of the methanol which is very low. This also eliminates any hazard of freezing during the winter.

Optimum chemical and thermal stability

-Methanol has an extremely high thermal stability, and there is no degradation by acidic components.

Non-corrosive

-Carbon steel can, therefore, be largely used for the equipment.

Good availability at very low cost

-Methanol is produced in bulk quantities for use as solvent and as raw material for a great number of industrial applications.

SECTION III: PROCESS DESCRIPTION

Three methanol absorption cycles are used for the complete purification of the crude gases. In the first cycle, so-called gas naphtha and water in the gas are removed by washing with a small quantity of methanol. The second cycle is designed to remove the bulk of the hydrogen sulfide and organic sulfur compounds from the gas. The third cycle removes carbon dioxide to the required level, using a relatively large circulation of methanol. The methanol streams are regenerated to remove the absorbed products.

The naphtha, recovered from the methanol by water displacement, is decanted and run to storage as a final product from the plant.

The Rectisol Plant serves a dual purpose.

(a) It produces a clean gas as required for the down-stream synthesis.

(b) It produces types of off-gas streams compatible with current processes commonly used for environmental protection.

To achieve (a) and (b), various Rectisol designs are possible. They differ in respect to the composition of the off-gases they produce, i.e. sulfur distribution, and also with the losses of valuable gases such as CH_4, C_2H_4, and C_2H_6.

In keeping with the philosophy of the study, an initial attempt has been made to optimise the sulfur removal and recovery system. However, a truly optimum design requires further investigation during a more detailed engineering phase.

In this system, H_2S is selectively washed out with part of the CO_2 in the lower section of the absorber while the remaining CO_2 and sulfur compounds such as COS are reduced to the required level in the absorber's upper section.

Approximately 30% of the H_2S is released in the flash gases while the balance of 70% is contained in the methanol fed to the hot regenerator from where it is stripped to produce an H_2S off-gas.

The gas leaving the Rectisol Plant is represented by Stream 13 to NH_3 synthesis and Stream 18 to Methanation. These streams are summarized as follows:

	Stream 13		Stream 18	
Component	lbmole/hr	Mole %	lbmole/hr	Mole %
CO_2	100.9	1.00	1390.9	3.65
H_2S	-	-	-	-
C_2H_4	35.4	0.35	129.8	0.34
CO	782.9	7.76	6139.4	16.12
H_2	7469.6	74.01	24172.3	63.46
CH_4	1591.3	15.77	5849.2	15.35
C_2H_6	67.4	0.67	249.0	0.65
N_2	44.9	0.44	164.7	0.43
Total Dry Gas	10092.4	100.00	38095.3	100.00
H_2O	-		-	

Before entering the Liquid N_2 Wash, Stream 13 passes through a final Rectisol Wash where the remainder of the CO_2 is removed. The gas entering the Liquid N_2 Wash, Stream 20, is summarized as follows:

	Stream 20	
Component	lbmole/hr	Mole %
CO_2	-	-
H_2S	-	-
C_2H_4	35.4	0.35
CO	782.9	7.84
H_2	7469.6	74.76
CH_4	1591.3	15.93
C_2H_6	67.4	0.67
N_2	44.9	0.45
Total Dry Gas	9991.5	100.00
H_2O		

The gas leaving the Rectisol Plant is represented by Stream 13 to NH_3 synthesis and Stream 18 to Methanation. These streams are summarized as follows:

	Stream 13		Stream 18	
Component	lbmole/hr	Mole %	lbmole/hr	Mole %
CO_2	100.9	1.00	1390.9	3.65
H_2S	-	-	-	-
C_2H_4	35.4	0.35	129.8	0.34
CO	782.9	7.76	6139.4	16.12
H_2	7469.6	74.01	24172.3	63.46
CH_4	1591.3	15.77	5849.2	15.35
C_2H_6	67.4	0.67	249.0	0.65
N_2	44.9	0.44	164.7	0.43
Total Dry Gas	10092.4	100.00	38095.3	100.00
H_2O	-		-	

Before entering the Liquid N_2 Wash, Stream 13 passes through a final Rectisol Wash where the remainder of the CO_2 is removed. The gas entering the Liquid N_2 Wash, Stream 20, is summarized as follows:

	Stream 20	
Component	lbmole/hr	Mole %
CO_2	-	-
H_2S	-	-
C_2H_4	35.4	0.35
CO	782.9	7.84
H_2	7469.6	74.76
CH_4	1591.3	15.93
C_2H_6	67.4	0.67
N_2	44.9	0.45
Total Dry Gas	9991.5	100.00
H_2O		

6.0 Liquid Nitrogen Wash

The gas leaving the final CO_2 wash enters the washing column of the Liquid N_2 Wash through a coil submerged in the liquid bottoms product. There the first separation takes place in that most of the CH_4, C_2H_4, and C_2H_6, and the better part of the CO, condense and are recovered as the so-called methane fraction. The remainder is then washed with liquid nitrogen, which is generated by isenthalpic expansion. In this wash all components except hydrogen leave with the bottoms. Only the hydrogen remains in the gaseous phase. The column is operated such that, through controlled evaporation of nitrogen, the hydrogen is recovered in a 3:1 mixture with the nitrogen. This is the composition required for ammonia synthesis. The bottoms product, after flashing, yields the so-called fuel gas fraction, which can be used elsewhere in the plant.

The methane fraction mentioned above is recovered, recompressed, and blended into Stream 18 for subsequent methanation.

The compositions of the NH_3 synthesis gas, Stream 22, the fuel gas, Stream 21, and the methane fraction, Stream 23, are summarized as follows:

	Stream 21		Stream 22	
Component	lbmole/hr	Mole %	lbmole/hr	Mole %
CO_2	-	-	-	-
H_2S	-	-	-	-
C_2H_4	2.3	0.24	-	-
CO	368.8	38.86	-	-
H_2	62.7	6.60	7339.2	75.00
CH_4	329.2	34.67	-	-
C_2H_6	4.3	0.45	-	-
N_2	182.1	19.18	2446.3	25.00
Total Dry Gas	949.4	100.00	9785.5	100.00

	Stream 23	
Component	lbmole/hr	Mole %
CO_2	-	-
H_2S	-	-
C_2H_4	33.1	1.75
CO	414.1	21.88
H_2	67.7	3.58
CH_4	1262.1	66.69
C_2H_6	63.1	3.33
N_2	52.5	2.77
Total Dry Gas	1892.6	100.00

The compositions of the NH_3 synthesis gas, Stream 22, the fuel gas, Stream 21, and the methane fraction, Stream 23, are summarized as follows:

	Stream 21		Stream 22	
Component	lbmole/hr	Mole %	lbmole/hr	Mole %
CO_2	-	-	-	-
H_2S	-	-	-	-
C_2H_4	2.3	0.24	-	-
CO	368.8	38.86	-	-
H_2	62.7	6.60	7339.2	75.00
CH_4	329.2	34.67	-	-
C_2H_6	4.3	0.45	-	-
N_2	182.1	19.18	2446.3	25.00
Total Dry Gas	949.4	100.00	9785.5	100.00

	Stream 23	
Component	lbmole/hr	Mole %
CO_2	-	-
H_2S	-	-
C_2H_4	33.1	1.75
CO	414.1	21.88
H_2	67.7	3.58
CH_4	1262.1	66.69
C_2H_6	63.1	3.33
N_2	52.5	2.77
Total Dry Gas	1892.6	100.00

7.0 Methanation

Stream 18 from Rectisol is combined with the CH_4 rich gas from the Liquid N_2 Wash, Stream 23, and fed to the Methanation Unit. This combined stream is represented by Stream 24 and is summarized below:

	Stream 24	
Component	lbmole/hr	Mole %
CO_2	1390.9	3.48
H_2S	-	-
C_2H_4	162.9	0.41
CO	6553.5	16.39
H_2	24240.0	60.62
CH_4	7111.3	17.78
C_2H_6	312.1	0.78
N_2	217.2	0.54
Total Dry Gas	39987.9	100.00

The purpose of the methanation unit is to catalytically convert to methane all of the CO in the feed gas and as much of the CO_2 as possible by consuming hydrogen. The principal reactions in methanation are described by the following chemical equations:

$$CO_2 + 4H_2 = CH_4 + 2H_2O \qquad \text{Exothermic}$$

$$CO + 3H_2 = CH_4 + H_2O \qquad \text{Exothermic}$$

$$CO + H_2O = CO_2 + H_2 \qquad \text{Exothermic}$$

Other minor reactions are the hydrogenation of any ethylene to ethane and hydrocracking of ethane to methane. At the conditions used, the formation of carbon is suppressed.

The methanation catalyst is highly sensitive to sulfur compounds. To remove any trace quantities of sulfur that might remain in the gas stream, because of maloperation or an upset of the Rectisol unit, a zinc oxide containing guard reactor is provided ahead of the methanation reactors. After sulfur removal, the process gas is proportioned between two catalytic reactor stages along with recycled methanated effluent gas which serves to limit the temperature rise across the reactors. The reactors are designed as fixed bed downflow units employing a pelleted reduced-nickel type catalyst.

The reaction heat is removed by generation of 600 psia steam in waste heat exchangers at the outlet from each reactor. Net gas leaving the synthesis loop is passed through the cleanup reactor to accomplish essentially complete conversion of carbon monoxide, and then is cooled by successive heat exchange with boiler feed water, fresh feed gas, air and cooling water. Water condensed from the gas is separated and forwarded for recovery as boiler feed water.

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The product SNG from the Methanation Unit is represented by Stream 25 and is summarized as follows:

Component	Stream 25 lbmole/hr	Mole %
CO_2	454.9	2.76
H_2S	-	-
C_2H_4	-	-
CO	16.5	0.10
H_2	247.1	1.50
CH_4	15534.3	94.32
C_2H_6	-	-
N_2	217.2	1.32
Total Dry Gas	16470.0	100.00

8.0 Gas Liquor Separation

All gas liquor and condensate streams from the various process steps are directed to the Gas Liquor Separation unit. The gas liquor contains tar, tar oil, and dissolved compounds such as phenols, ammonia, carbon dioxide, and hydrogen sulfide. Tar is defined as a heavier than water organic liquid phase, while tar oil is the lighter than water organic liquid phase.

The gas liquor separation unit is designed to separate tar-oil, gas liquor, and tar from the gas liquor feed streams by gravity decantation. The feed streams are: dusty gas liquor from the gasification unit, tarry gas liquor from the first stages of gas cooling, and oily gas liquor

from the latter stages of gas cooling. The dusty gas liquor is kept separated from the tarry and oily gas liquors during processing but are all eventually combined before leaving the unit. All of these gas liquors are produced as a result of subjecting the crude gas produced in coal gasification to successive stages of cooling.

The various streams of gas liquor from the process units are cooled, expanded, and introduced into the tar separators. The tar separators make a three-phase separation between tar-oil, gas liquor, and tar. In addition, a tar and dust mixture is settled to the bottom to be drawn off and recycled back to the gasification section for injection into the gasifiers. The gas liquor phase is then subjected to an additional series of phase separations where more of the tar and tar oil are drawn off. The final gas liquor, free of tar-oil and tar, is transferred to the Phenosolvan Plant.

The tarry gas liquor also undergoes separation into three liquid phases after initial cooling and expansion. The tarry gas liquor from this phase separation is then combined with oily gas liquor which also has undergone cooling, expansion, and a single stage separation. The final combined gas liquor is then subjected to a final settling and separation step in a storage tank before being pumped to the Phenosolvan Plant for phenol extraction.

The separated tar-oil and tar phases are handled in a collection and surge system from which they are pumped to storage as final products from the plant.

Flash gases resulting from the pressure reductions of all the gas liquor feed streams are water-scrubbed for removal of ammonia and the ammonia-free gases are incinerated. Vent gases from all settling and surge tanks are also incinerated.

9.0 Phenosolvan

The Phenosolvan Section consists of phenol extraction, gas liquor stripping, and solvent recovery areas.

The gas liquor from the [illegible] Separation Section passes through a gas liquor filter where any tar, oil, or solids are removed before it enters the phenol recovery scrubber where residual quantities of phenol in the stripping nitrogen are recovered into the crude gas liquor. From the bottom of this scrubber the gas liquor enters a multistage extractor where it is contacted with a countercurrent flow of isopropyl ether which extracts most of the monovalent phenols and about 50% of the multivalent phenols from the aqueous phase.

The gas liquor leaves the extractor with an equilibrium amount of dissolved solvent and phenol and enters a solvent stripper, where the dissolved solvent is stripped from the gas liquor with recycled nitrogen.

The remaining gas liquor containing the following contaminants is transferred to the Biological Waste Treatment Plant.

NH_3 = 100 ppm (weight)

H_2S = 20 ppm (weight)

CO_2 = 50 ppm (weight)

HCN = 20 ppm (weight)

Monophenol = 30 ppm (weight)

Multiphenols = 640 ppm

The extract phase from the extractor, consisting of solvent and dissolved phenols, enters a distillation column where the solvent is distilled off and returned to the extractor. The crude phenol is pumped to a storage tank.

Nitrogen, which is used in the solvent stripper to remove solvent from the gas liquor, leaves the tope of the stripper laden with solvent and is scrubbed with crude phenol in a solvent recovery scrubber. The nitrogen gas leaves the top of this scrubber and is recycled to the solvent stripper.

10.0 Chemie Linz-Lurgi Process (CLL)

Approximately 80% of the nitrogen in the coal is recovered as ammonia in the gas liquor. The Phenosolvan Process removes the phenols and can also remove ammonia, CO_2, and H_2S. In the past, the ammonia left the Phensolvan unit in the form of an ammonia and steam vapor with an NH_3 concentration of 5-25%. Some plants used it for the manufacture of ammonium sulfate while others sold an ammonia liquor as liquid fertilizer. However, SNG from coal plants produce enough ammonia to make the production of anhydrous liquid ammonia very economical, or even a necessity to avoid excessive shipping costs.

In collaboration with Chemie Linz AG (Osterreichische Stickstoffwerke at Linz, Austria) LURGI has developed a process which produces anhydrous ammonia from dephenolized gas liquor. After dephenolization the gas liquor contains ammonia as well as CO_2, H_2S and

traces of HCN. To recover the ammonia from the gas liquor, recourse was taken to the commercially proven process of Chemie Linz for the separation of ammonia from CO_2 in melamine production. It was modified to suit the requirements of the gasification process and is now part of the overall Lurgi coal gasification system.

The dephenolized gas liquor from the Phenosolvan plant is subjected to a two-stage stripping process in the CLL plant to remove CO_2 and H_2S, to make anhydrous ammonia and to produce a waste gas liquor stream suitable for treatment in a Biological treatment plant.

The dephenolized gas liquor enters the deacidifier column after being preheated indirectly by hot stripped gas liquor leaving the plant. In the deacidifier column the acid gases and inert gases are stripped with low pressure steam and then scrubbed with a cooled part of the feed liquor and additional fresh water to remove NH_3.

Accumulated traces of entrained solvent can also be withdrawn from this column. The CO_2 and H_2S off-gas from this column are then sent as an additional feed stream to the sulfur recovery plant.

The deacidifier bottom product leaves the column, exchanges heat with cold fresh incoming gas liquor and is then passed into the gas liquor stripping column. Here ammonia and final traces of H_2S and CO_2 are removed as an overhead gas stream. This overhead stream is then passed into the CO_2 scrubber for further ammonia concentration.

The overheads from the CO_2 scrubber contain over 96% NH_3, some water and traces of CO_2, H_2S, and HCN. The overheads are then sent via a demister into an ammonia liquefaction unit.

Between the compression steps of the liquefaction unit an additional scrubbing with liquid NH_3 is necessary to remove the previously mentioned traces from the compressed NH_3 vapors. The anhydrous, liquefied ammonia has the following specification:

	Guaranteed	Expected
NH_3	99.7 w %	99.9 w%
CO_2	0.1 w %	0.03 - 0.05 w %
H_2S	10 ppm (w)	1 ppm (w)
H_2O/Inerts	Balance	Balance

The ammonia-free liquor leaving the CLL plant is transferred to the Biological Treatment Plant.

The composition of the waste water stream contaminants at this point is, typically:

Monovalent Phenols	30 PPM
Free ammonia	100 PPM
CO_2	50 PPM
H_2S	Traces

Approximately 65-70% of the multivalent phenols present in the original gas liquor are still present after treatment in the Phenosolvan and CLL plants.

Also, all the fixed ammonia, cyanides, and approximately 80% of the fatty acids are unaffected and remain in the waste liquor stream to the Biological Treatment Plant.

11.0 Stream Flowrates and Compositions

The flows and compositions of the major process streams are presented in the following tables.

Gasification, Shift conversion, Gas Cooling

	STREAM NO.		1		2		3		4		5	
	COMPONENTS	Mol. wt.	lb mols/hr	mol %	lb mols/hr	mol %	lb mols/hr	mol %	lb mols/hr	mol %	lb mols/hr	mol %
	CO_2	44.010			-	-	1118.0	32.65	23042.3	32.65		
	H_2S	34.076			-	-	10.3	0.30	211.7	0.30		
	COS	60.070			-	-	-	-	-	-		
	C_2H_4	28.054			-	-	15.4	0.45	317.6	0.45		
	CO	28.010			-	-	558.5	16.31	11510.6	16.31		
	H_2	2.016			-	-	1316.3	38.44	27128.5	38.44		
	CH_4	16.043			-	-	372.2	10.87	7671.3	10.87		
	C_2H_6	30.070			-	-	23.3	0.68	479.9	0.68		
	N_2 + inerts	28.013			187.4	2.00	10.3	0.30	211.7	0.30		
	O_2	31.999			9186.4	98.00	-	-	-	-		
	TOTAL DRY GAS				9373.8	100.00	3424.3	100.00	70573.6	100.00		
3	H_2O	18.015			-	-	-	-	75202.9	-		
9	TOTAL WET GAS				-	-	-	-	145776.5	-		
0	DRY GAS	Lbs/hr			299,206							
21	H_2O											
22	TAR								39,735			
23	OIL								8,477			
24	NAPHTHA								4,768			
25	ORG. S.											
26	OTHERS (1)								9690/9050/2720(2)			
27	DUST											
30	TOTAL		1,462,610 (1)		299,206						105,580 (3)	
31	PRESSURE	psig	Atmos		483		5		426		Atmos	
32	TEMPERATURE	°F	60		212		122		523		932	
33	MOL. WT. DRY GAS											

(1) ASP Coal; (2) Phenol/NH_3 /fatty acids; (3) Ash w/5, 270 lb. c

Gasification , Shift conversion , Gas Cooling

	STREAM NO.		6		7		8		9		10	
	COMPONENTS	Mol. wt.	lb mols/hr	mol %	lb mols/hr	mol %	lb mols/hr	mol %	lb mols/hr	mol %	lb mols/hr	mol %
	CO_2	44.010	23042.3	32.65					13409.6	32.65	17970.1	39.39
	H_2S	34.076	211.7	0.30					123.2	0.30	123.2	0.27
	COS	60.070							-	-	-	-
	C_2H_4	28.054	317.6	0.45					184.8	0.45	184.8	0.40
	CO	28.010	11510.6	16.31					6698.7	16.31	2138.2	4.69
	H_2	2.016	27128.5	38.44					15787.7	38.44	20348.2	44.59
	CH_4	16.043	7671.3	10.87					4464.4	10.87	4464.4	9.78
3	C_2H_6	30.070	479.9	0.68					279.3	0.68	279.3	0.61
5	N_2 + Inerts	28.013	211.7	0.30					123.2	0.30	123.2	0.27
1	O_2	31.999							-	-	-	-
2	TOTAL DRY GAS		70573.6	100.00	-	-	-	-	41070.9	100.00	45631.4	100.00
3	H_2O	18.015	46814.0	-	28388.9	-	11870.0	-	20336.0	-	15775.5	-
9	TOTAL WET GAS		117387.6	-	-	-	-	-	61406.9	-	61406.9	-
20	DRY GAS	Lbs/hr										
21	H_2O	"			511,426		213,838					
22	TAR	"			39.735 (1)							
23	OIL	"			8,477 (1)							
24	NAPHTHA	"										
25	CRG. S.	"										
26	OTHERS (1)	"										
27	DUST	"										
50	TOTAL	"										
51	PRESSURE	psig	420		420		412		412		401	
52	TEMPERATURE	°F	367		374		359		352		513	
53	MOL.WT. DRY GAS											

(1) 100% of Tar and Oil for all gas liquor streams shown in Stream 7

Gasification . Shift conversion . Gas Cooling

STREAM NO.			11		12		13		14		15	
	COMPONENTS	Mol. wt.	lb mols/hr	mol %	lb mols/hr	mol %	lb mols/hr	mol %	lb mols/hr	mol %	lb mols/hr	mol %
	CO_2	44.010	6606.1	39.39	6606.1	39.39	100.00	1.00	11364.0	39.39	9632.7	32.65
	H_2S	34.076	45.3	0.27	45.3	0.27	-	-	77.9	0.27	88.5	0.30
	COS	60.070	-	-	-	-	-	-	-	-	-	-
	C_2H_4	28.054	67.9	0.40	67.9	0.40	35.4	0.35	116.9	0.40	132.8	0.45
	CO	28.010	786.0	4.69	786.0	4.69	782.9	7.76	1352.2	4.69	4811.9	16.31
	H_2	2.016	7480.4	44.59	7480.4	44.59	7469.6	74.01	12867.8	44.59	11340.8	38.44
	CH_4	16.043	1641.2	9.78	1641.2	9.78	1591.3	15.77	2823.2	9.78	3206.9	10.87
	C_2H_6	30.070	102.7	0.61	102.7	0.61	67.4	0.67	176.6	0.61	200.6	0.68
	N_2 + inerts	28.013	45.3	0.27	45.3	0.27	44.9	0.44	77.9	0.27	88.5	0.30
	O_2	31.999	-	-	-	-	-	-	-	-	-	-
1	TOTAL DRY GAS		16774.9	100.00	16774.9	100.00	10092.4	100.00	28856.5	100.00	29502.7	100.00
3	H_2O	18.015	5799.3	-	23.0	-	-	-	9974.2	-	14608.0	-
8	TOTAL WET GAS		22574.2	-	16797.9	-	-	-	38830.7	-	44110.7	-
20	DRY GAS	Lbs/hr										
21	H_2O	"										
22	TAR	"										
23	OIL	"										
24	NAPHTHA	"										
25	ORG. S.	"										
26	OTHERS (1)	"										
27	DUST	"										
50	TOTAL	"										
51	PRESSURE	psig	401		398		370		401		412	
52	TEMPERATURE	°F	513		86		64		513		352	
53	MOL.WT. DRY GAS											

Gasification . Shift conversion . Gas Cooling

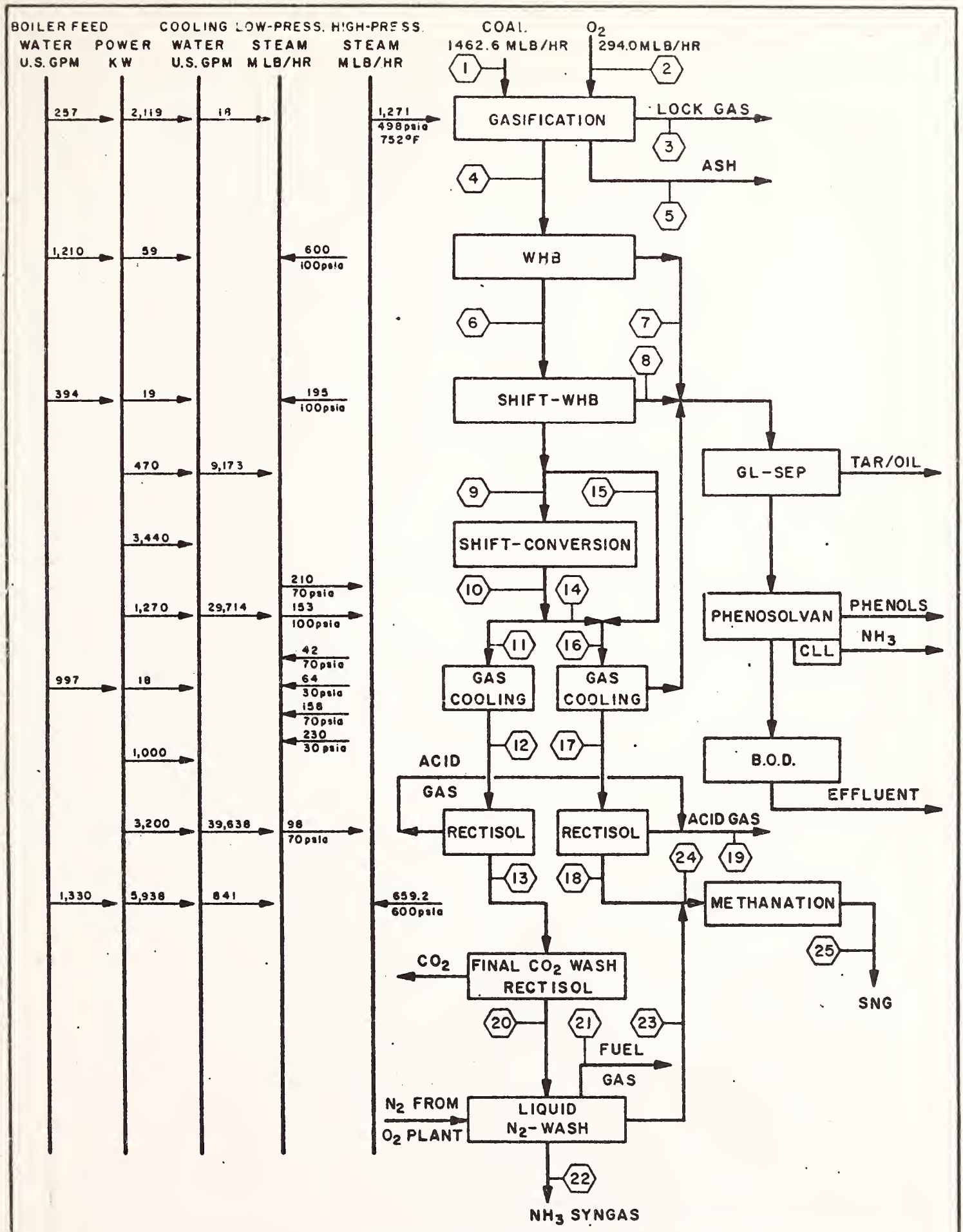
	STREAM NO.		16		17		18		19		20	
	COMPONENTS	Mol. wt.	lb mols/hr	mol %	lb mols/hr	mol %	lb mols/hr	mol %	lb mols/hr	mol %	lb mols/hr	mol %
	CO_2	44.010	20996.7	35.97	20996.7	35.97	1390.9	3.65	26111.0	96.90	-	-
	H_2S	34.076	166.4	0.29	166.4	0.29	-	-	211.7	0.79	-	-
	COS	60.070	-	-	-	-	-	-	-	-	-	-
	C_2H_4	28.054	249.7	0.43	249.7	0.43	129.8	0.34	152.4	0.56	35.4	0.35
	CO	28.010	6164.1	10.56	6164.1	10.56	6139.4	16.12	27.8	0.10	782.9	7.84
	H_2	2.016	24208.6	41.48	24208.6	41.48	24172.3	63.46	47.1	0.17	7469.6	74.76
	CH_4	16.043	6030.1	10.33	6030.1	10.33	5849.2	15.35	230.8	0.86	1591.3	15.93
	C_2H_6	30.070	377.2	0.65	377.2	0.65	249.0	0.65	163.5	0.61	67.4	0.67
	N_2 + Inerts	28.013	166.4	0.29	166.4	0.29	164.7	0.43	2.1	0.01	44.9	0.45
	O_2	31.999	-	-	-	-	-	-	-	-	-	-
2	TOTAL DRY GAS		58359.2	100.00	58359.2	100.00	38095.3	100.00	26946.4	100.00	9991.5	100.00
3	H_2O	18.015	24584.2	-	80.0	-	-	-	-	-	-	-
6	TOTAL WET GAS		82943.4	-	58439.2	-	-	-	-	-	-	-
20	DRY GAS	Lbs/hr										
21	H_2O	"										
22	TAR	"										
23	OIL	"										
24	NAPHTHA	"										
25	ORG. S.	"										
26	OTHERS (1)	"										
27	DUST	"										
50	TOTAL	"										
51	PRESSURE	psig	401		398		370		9		365	
52	TEMPERATURE	°F	439		86		64		40		64	
53	MOL.WT. DRY GAS											

Gasification . Shift conversion . Gas Cooling

STREAM NO.			21		22		23		24		25	
	COMPONENTS	Mol. wt.	lb mols/hr	mol %	lb mols/hr	mol %	lb mols/hr	mol %	lb mols/hr	mol %	lb mols/hr	mol %
	CO_2	44.010	-	-	-	-	-	-	1390.9	3.48	454.9	2.76
	H_2S	34.076	-	-	-	-	-	-	-	-	-	-
	COS	60.070	-	-	-	-	-	-	-	-	-	-
	C_2H_4	28.054	2.3	0.24	-	-	33.1	1.75	162.9	0.41	-	-
	CO	28.010	368.8	38.86	-	-	414.1	21.88	6553.5	16.39	16.5	0.10
	H_2	2.016	62.7	6.60	7339.2	75.00	67.7	3.58	24240.0	60.62	247.1	1.50
	CH_4	16.043	329.2	34.67	-	-	1262.1	66.69	7111.3	17.78	15534.3	94.32
	C_2H_6	30.070	4.3	0.45	-	-	63.1	3.33	312.1	0.78	-	-
	N_2 + Inerts	28.013	182.1	19.18	2446.3	25.00	52.5	2.77	217.2	0.54	217.2	1.32
	O_2	31.999	-	-	-	-	-	-	-	-	-	-
2	TOTAL DRY GAS		949.4	100.00	9785.5	100.00	1892.6	100.00	39987.9	100.00	16470.0	100.00
3	H_2O	18.015	-	-	-	-	-	-	-	-	-	-
9	TOTAL WET GAS		-	-	-	-	-	-	-	-	-	-
20	DRY GAS	Lbs/hr										
21	H_2O	"										
22	TAR	"										
23	OIL	"										
24	NAPHTHA	"										
25	ORG. S.	"										
26	OTHERS (1)	"										
27	DUST	"										
30	TOTAL	"										
31	PRESSURE	psig	5		340		5		370		355	
32	TEMPERATURE	°F									86	
33	MOL. WT. DRY GAS											

12.0 Utilities Balances

The process block flow diagram and the individual process utilities requirements are present in Drawing No. P-309-1.



MONTANA INTERNATIONAL TRADE COMMISSION

MEF No. KGD-00-0791

DRAWN V.N.

CHKD

APPD

DATE 8-1-07

LURGI

AMERICAN LURGI CORPORATION

DRAWING TITLE

FLOW DIAGRAM & UTILITIES BALANCE MONTANA LIGNITE

DRAWING NO. P-309-1

REV. 0

APPENDIX D

APPENDIX D

THE LUMMUS COMPANY

MONTANA INTERNATIONAL TRADE COMMISSION

COAL GASIFICATION
FEASIBILITY STUDY

8 3223
August, 1976

TABLE OF CONTENTS

I. INTRODUCTION

This report covers the technical and economic definition of a coal gasification plant to produce 150 MM SCFD of pipeline-quality gas and 1000 ST/D of anhydrous ammonia. The conceptual design of this plant is based on the Lurgi coal gasification process and the use of Montana lignite. This study was prepared at the request of the Montana International Trade Commission as part of an overall Montana coal gasification study.

II. SUMMARY

In recognition of a potential shortage of natural gas in Montana, the Montana International Trade Commission has undertaken an analysis of possible steps that can be taken to alleviate a limited supply of natural gas. One part of this overall program involves the production of pipeline gas and synthetic ammonia through means of demonstrated and available technology. The Lummus Company was requested to submit information for a coal gasification plant conceptually designed to produce 150 MM SCFD of pipeline-quality gas and 1000 ST/D of anhydrous ammonia.

The site of the facility is assumed to be in Montana near the coal mining facilities and in an area that has adequate water supply from the Missouri River. The technical definition of the coal gasification plant is based on the report of American Lurgi, Reference No. KGD-00-0791, dated June, 1976 and transmitted to Lummus on June 21, 1976. Lummus technology was used to convert raw synthesis gas to anhydrous ammonia and in the design of the utility systems required for this plant.

Using in-house data developed by Lummus from similar studies made for other organizations, Lummus estimates that the total installed cost of the plant will be about $552 MM. The cost is an order of magnitude estimate, and it has to be recognized that an accurate assessment of the cost of these facilities will require a considerable design investigating effort and is, of course, subject to changes outside the control of Lummus. In the body of the report, a breakdown of various segments of the plant is given.

In order to enable the Montana International Trade Commission to develop production cost of ammonia and SNG, significant data have been presented relating to operating requirements of this plant.

The study describes a complete grass roots plant processing run-of-mine coal similar to North Dakota lignite. An analysis of Montana lignite was not given to Lummus, and any changes from the assumed value in the coal may have to be evaluated if the concept of this plant is to be developed in further detail.

The product gas obtained from the process unit is available at about 400 psig and is compressed and delivered to the property limits of the plant at an assumed delivery pressure of 1000 psig into an assumed gas transmission pipeline. It has also been assumed that water will be available from the Missouri River to satisfy the requirements for cooling and process water. The plant is conceived to include all other facilities necessary for a self-sustaining operation, such as coal handling and processing, steam generation, cooling water towers, buildings, and storage facilities. It has been assumed that electrical power requirements for the plant will be supplied by the local utility company.

II. SUMMARY - cont'd

The plant has been developed on the basis of minimizing electrical power requirements and generating sufficient quantities of steam to provide energy for compressors through the application of steam turbines. In this initial phase, it has been assumed that coal fines obtained from the coal preparation area will be used as fuel to the boilers, and liquid hydrocarbon by-products would be available for sale.

Attempts have been made to include a variety of systems to treat both liquid and gaseous effluents to meet environmental regulations. This particular segment of the plant will require significant investigation together with the Montana State bodies that are concerned with the protection of the environment.

To assist the Montana International Trade Commission in its plans, Lummus has included a project schedule which shows the various tasks that have to be undertaken to define, engineer, and construct the facilities. On the assumption that a forward program can evolve, it is estimated that the time required for engineering, procurement, construction, and initial operations of the plant will be about seven years.

III. SCOPE OF STUDY

The purpose of this study is to evaluate the feasibility of installing a facility to produce 150 MM SCFD of pipe-line quality gas and 1000 ST/D of ammonia by coal gasification using Lurgi technology.

The following elements were included in the study:

1. Plant definition and distribution of process units and offsites.

2. Process block flow diagram and material balance.

3. Plant energy balance.

4. Operating requirements including consumption of raw materials, electric power, catalyst and chemicals and personnel requirements.

5. Capital cost estimates of process units and offsites.

6. Overall plant layout and space requirements for process units and offsites.

7. Environmental considerations.

IV. PLANT ECONOMICS

Economic data developed for this plant include plant total installed cost (TIC), raw materials, utilities, catalyst and chemicals consumptions, and personnel requirements. In addition, a project schedule showing the relative time durations of major engineering, procurement and start-up activities from the time of contract award, has been included.

a. Total Installed Cost

The total installed cost was estimated at $551.7 MM. This figure was developed from in-house data used in previous studies. All materials costs used in developing this estimate represent July 1976 costs. In developing this estimate it was also assumed that electric power will be supplied from a nearby utility and that the jobsite is near residential communities, thereby eliminating the need for a construction camp. A breakdown of the cost of the individual processing units and offsites is given in table 1.

Estimate of Total Installed Cost (TIC) of Plant

TABLE 1

Area	Description	Total, $M
1100	Gasification	86,500
1200	Shift Conversion	12,700
1300	SNG Gas Cooling	7,500
1310	NH_3 Gas Cooling	3,100
1400	Rectisol	43,200
1600	Phenosolvan & NH_3 Recovery	25,200
1700	Methanation	21,300
1800	Gas Liquor Separation	8,300
1900	Product Gas Compression & Drying	9,600
2000	Coal Preparation & Handling	46,500
3000	Air Separation Unit	50,500
3100	N_2 Compression & Liquid N_2 Wash	7,200
3200	NH_3 Synthesis Loop	23,300
3300	NH_3 Refrigeration	300
4000	Sulfur Recovery	16,200
5000	Steam Generation & Distribution	89,300
5200	Stack Gas Scrubbing	22,600
5400	Raw Water Supply & Treating	14,700
5500	Cooling Water	11,900
5600	Fire Protection System	900
5700	Miscellaneous Utilities	900
6000	Offsite Storage and Loading Facilities	4,900
7000	Plant Interconnecting Piping	10,000
8100	Liquid Waste Effluent System	4,700
8200	Ash Disposal	3,300
8300	Flare System	2,800
	SUBTOTAL	527,400
	Site Development	11,100
	Buildings	8,400
	Freight	4,800
	TOTAL BASIC PLANT COST	551,700

b. Operating Data

Plant operating data includes the consumption of raw materials, utilities, catalyst and chemicals. A table summarizing products and by-products, available for sale or for use as fuel within the plant is also included.

In preparing the plant operating requirements, it was assumed that 4874 ST/day of coal fines generated during coal preparation would be sufficient to satisfy fuel requirements for steam generation of 67.2 x 10^9 Btu/day, while process by-products would be available for export. These by-products shown in Table 2 have a total fuel value of 29.1 x 10^9 Btu/day. As an alternate, one might consider using them to satisfy part of the boiler fuel requirements, and using 2763 ST/day of coal fines to meet the balance of 38.1 x 10^9 Btu/day. Coal fines in excess of this tonnage would be exported in lieu of the hydrocarbon by-products.

Consumptions of raw materials, utilities catalyst and chemicals shown below were developed by prorating in-house design data. Catalysts and chemicals costs shown are based on 1976 prices.

TABLE 2

Operating Data

Consumption of Coal & Utilities		
Coal to Plant (as received)		
Coal to Gasification	17,551	ST/day
Coal fines to steam-generation	4,874	ST/day
TOTAL	22,425	ST/day
Electric Power	58,000	KWH/hr
Raw Water	6,080	GPM
Consumption of Catalysts & Chemicals		
Shift Catalyst (assuming 4 yr. life)	$ 440	/day
Methanation Catalyst (assuming 2 yr. life)	$2,065	/day
Ammonia Synthesis Catalyst (assuming 3 yr. life)	$ 160	/day
Methanol (100%)	38,000	lbs/day
Phenosolvan Solvent (di-isopropylether)	3,060	lbs/day
Stretford Solution Chemicals	$2,160	/day
Water Treating Chemicals	$1,160	/day
Products and By-Products	**Per Stream Day**	
SNG @ 957 BTU/SCF	150	MM SCF
Fuel Gas @ 508 BTU/SCF	8.6	MM SCF
Naphtha (123,000 BTU/Gal)	17,840	Gal.
Tar Oil (133,000 BTU/Gal)	27,440	Gal.
Tar (147,000 BTU/Gal)	106,990	Gal.
Crude Phenols (122,000 BTU/Gal)	25,880	Gal.
Anhydrous Ammonia	1,107	ST
Sulfur	73	LT
Sulfuric Acid	110	ST

IV. PLANT ECONOMICS - Cont'd

c. Personnel Requirements

Plant operations, administration and maintenance personnel requirements were estimated based on in-house plant staffing information.

TABLE 3

Personnel Requirements

Operations and Administration	No. of Personnel	Total Annual Salary
Plant Manager	1	$ 42,000
Assistant Plant Manager	1	33,000
Superintendents	3	90,000
Supervisors	50	1,150,000
Engineers	34	680,000
Foremen	6	99,000
Operators, Lab Tech.	250	3,300,000
Clerical	33	297,000
		$5,691,000
Add 30% for Overhead		1,707,300
		$7,398,300
Maintenance		
Superintendents	1	30,000
Supervisors	9	207,000
Engineers	9	180,000
Foremen	32	528,000
Craftsmen, Helpers, Laborers	275	3,630,000
Clerical	6	54,000
		$4,629,000
Add 30% for Overhead		1,388,700
		$6,017,700

IV. PLANT ECONOMICS - Cont'd

d. PROJECT SCHEDULE

The project schedule delineates the major activities and their time relations required to complete the project.

The schedule takes into account the present market conditions and delivery of equipment and materials.

In the development of this schedule certain parameters were analyzed in order to arrive at the start of gas production date of November 1982, with complete on stream operation by September 1983. In principle, the schedule has tried to minimize the financial risks by deferring extensive procurement activities until after regulatory approval is received. However, certain critical equipment such as draglines may need to be requisitioned prior to receipt of such approval.

Factors that have a direct impact on the proposed schedule are as follows:

1. Delivery of draglines.

2. Starting date and duration of Lurgi detailed engineering data.

3. Approval from regulatory agencies.

4. Delivery of major equipment and materials.

The schedule is based on selecting a contractor by January 1, 1977. Approval from regulatory agencies is anticipated by January 1979, and start of construction is scheduled at the same time.

Delivery of equipment and commodities will begin in 1980 and continue until mid 1982. Plant areas will be turned over for precommissioning beginning in March 1981 and continuing through 1982. Start of gasification and gas production is scheduled for November 1982, and continuing until full gas production rate is achieved in September 1983.

AMC

DESCRIPTION
CONTRACTOR SELECTION
PHASE I
SITE INVESTIGATION & SELECTION
RECEIVE LURGI DATA FOR PRELIMINARY FEASIBILITY STUDY
PREPARE PRELIMINARY DESIGN
PREPARE PRELIMINARY ESTIMATES
SUBMIT PRELIMINARY FEASIBILITY REPORT
RECEIVE FINAL LURGI DATA FOR FEASIBILITY REPORT
PREPARE DESIGN OF DOWNSTREAM PROCESS UNITS UTILITIES AND AUXILIARY FACILITIES
PREPARE ESTIMATE
PREPARE PROJECT SCHEDULE
PREPARE FEASIBILITY REPORT
SUBMIT FEASIBILITY REPORT
ASSIST CLIENT IN PREPARING APPLICATION TO REGULATORY AGENCIES
FILE APPLICATIONS TO REGULATORY AGENCIES
PHASE II
PREPARE FINAL PROCESS DESIGN AND EQUIPMENT SPECIFICATIONS
COMPLETE ARRANGEMENT DRAWINGS AND ENGINEERING SPECIFICATIONS
OBTAIN FIRM COMPETITIVE QUOTATIONS
COMMIT ORDERS FOR CRITICAL EQUIPMENT
ENGINEERING FOR REFINED ESTIMATES
PREPARE REFINED ESTIMATES
SUBMIT REFINED ESTIMATE
ANTICIPATED APPROVAL FROM REGULATORY AGENCIES
PHASE III
DETAILED ENGINEERING DESIGN
PROCUREMENT
MATERIAL AT SITE
SITE WORK
CONSTRUCTION
OPERATOR TRAINING
START-UP ASSISTANCE
FULL OPERATION
CRITICAL EQUIPMENT
DRAG LINE #1, #2 & #3
LOADING SHOVEL #1, #2 & #3
HAUL TRUCKS
MAIN TURBINE DRIVES & COMPRESSORS
COAL FIRED BOILERS
OXYGEN PLANT COLD BOX
TOTAL THIS PAGE
TOTAL

MONTHS

1977 1978 1979 1980 1981 1982 1983 1984

1st delv. drag line — 2nd delv. drag line — 3rd delv. drag line — first gas — full gas production

LEGEND

—— - ACTIVITY DURATION ○ - DELIVERY AT SITE

R - ISSUE FOR INQUIRY ⚐ KEY MILESTONE DATE

▲ - ISSUE FOR PURCHASE

LUMMUS

JOB NO. B-3223

DATE ISSUED JULY 23, 1976

REPORT AS OF JULY 23, 1976

COAL GASIFICATION FEASIBILITY STUDY
FOR
MONTANA INTERNATIONAL TRADE COMMISSION

AREA

PAGE 1 OF 1

V. OVERALL PLANT DESCRIPTION

The Coal Gasification Plant to be located in Montana is a grass roots plant and includes all process systems, utility and environmental support facilities, tankage, buildings, and electric power generating facilities. The complex will produce 150 MM SCFD of synthetic pipeline gas and 1,000 ST/D of anhydrous ammonia. The product SNG will have a minimum HHV of 957 BTU/SCF measured at 14.73 psia, 60°F, and dry basis.

The design is based on the Lurgi Pressure Gasification Process. Non-proprietary process units, offsites, sulfur recovery, and waste effluent control systems were designed by Lummus.

The Process Flow Diagram and Material Balance Sketch No. 1 shows the major processing areas. Sized coal is delivered to the gasifier feed system. The coal enters each gasifier through a lock-hopper system and passes downward while being gasified. Steam and oxygen are introduced at the bottom of the gasifier to effect the coal gasification reactions. A revolving grate supports the coal bed, cleans out the ash, and distributes the steam-oxygen mixture. The gasifier is designed to remove the ash as a solid particulate through an ash lock hopper. The ash is dumped into a hydraulic sluicing system and is conveyed to the ash handling area, where it is concentrated by mechanical means and is subsequently trucked to the mine for disposal.

The hot, crude product gas leaving the gasifier reactor is cleaned of tar and dust by cooling in quench vessels, steam generators, and coolers. The tar oil is recovered from the quench water. A portion of the crude gas is passed through shift conversion reactors.

The effluent leaving the shift converter is divided into two streams. The larger portion of the shift converter effluent is combined with the portion of the crude gas that bypassed the shift converters and is further processed for SNG production. The smaller portion of the shift converter effluent is further processed for ammonia production.

The combined gas stream that is used for SNG production is cooled through heat exchangers to recover sensible heat, additional oil, and naphtha.

V. OVERALL PLANT DESCRIPTION - cont'd

The gas stream, which consists of methane, ethane, hydrogen, hydrogen sulfide, carbon monoxide, carbon dioxide and nitrogen, is then purified of hydrogen sulfide and carbon dioxide. This is accomplished by absorption using cold methanol in the Rectisol unit. The purified gas is methanated to remove almost all the residual carbon monoxide and a portion of the carbon dioxide by reaction with hydrogen to produce methane. This raises the heating value so that the synthetic gas can be blended with natural gas. The product gas is dried and compressed for delivery to the pipeline.

The shift converter effluent gas used for ammonia production is also cooled in a parallel cooling train and then is purified of hydrogen sulfide and carbon dioxide in a separate two stage Rectisol system.

Leaving the second stage Rectisol unit, the process gas passes through a liquid nitrogen wash, where all the methane, ethylene, and ethane present are condensed, leaving only the hydrogen and nitrogen in the vapor state. The hydrogen/nitrogen mixture composition is adjusted with additional nitrogen to a 3:1 ratio and passes to the ammonia synthesis loop. The gas entering the synthesis loop is compressed, preheated, and catalytically converted to ammonia. The ammonia product is cooled and condensed for delivery to product storage.

The oxygen required for the gasifiers and the nitrogen required for the liquid nitrogen wash and ammonia synthesis is supplied from the self-contained air separation plant included in the complex.

The Stretford unit processes the carbon dioxide containing hydrogen sulfide from the Rectisol unit and converts the H_2S into saleable elemental sulfur in liquid form.

The production of SNG and ammonia from coal requires a steady supply of steam and electric power. High-pressure steam (1,500 psig) is generated in coal-fired boilers using coal fines obtained from the coal preparation section. Medium-pressure steam (550 psig) is produced in process waste heat boilers and from higher pressure steam let down through steam turbines. Electric power is supplied to the plant by a local utility company.

The complex is designed with maximum reliability built into the system to minimize the possibility of interruption in gas production. Independent, parallel processing systems are employed to minimize the effect of the loss of a process unit. In addition, spare equipment is provided at critical points. The process train philosophy is shown on the Process Train Arrangement Diagram shown in Sketch 5.

The environmental control systems are conceived to be integrated with the process units, waste heat recovery, cooling water, and ash handling systems. Wherever possible, water reuse was incorporated in the design.

V. OVERALL PLANT DESCRIPTION - cont'd

TABLE NO. 3 - ENERGY BALANCES

Approximate energy balances were calculated for the overall plant and the gasification section as follows:

OVERALL PLANT ENERGY BALANCE

Input	Quantity	10^9 BTU/D	HHV%
Coal to plant (35.02% moisture, 6.86% ash, and 6,894 BTU/lb HHV)	22,425 ST/D	309.2	98.5
Electric power consumption	58,000 KWH/HR	4.8	1.5
TOTAL INPUT		314.0	100.0
Output			
Pipeline-quality Gas (957 BTU/SCF HHV)	150 MM SCFD	143.5	45.7
Anhydrous Ammonia (9,800 BTU/lb HHV) (total produced)	1,107 ST/D	21.7	6.9
Fuel Gas (508 BTU/SCF HHV)	8.6 MM SCFD	4.4	1.4
Liquid By-products (tar, tar oil, naphtha, and phenols)		24.7	7.9
TOTAL OUTPUT		194.3	61.9 → 60.1 w/10-02

GASIFICATION ENERGY BALANCE

Input			
Coal to gasifiers (35.02% moisture, 6.86% ash, and 6,894 BTU/lb HHV)	17,551 ST/D	242.0	100.0
Output			
Pipeline-quality Gas (957 BTU/SCF HHV)	150 MM SCFD	143.5	59.3
Anhydrous Ammonia (9,800 BTU/lb. HHV) (total produced)	1,107 ST/D	21.7	9.0
Fuel Gas (508 BTU/SCF HHV)	8.6 MM SCFD	4.4	1.8
Tar (147,000 BTU/Gal)	106,990 Gal/D	15.7	6.5
Tar oil (133,000 BTU/Gal)	27,440 Gal/D	3.6	1.5
Naphtha (123,000 BTU/Gal)	17,840 Gal/D	2.2	.9
Crude Phenols (122,000 BTU/Gal)	25,880 Gal/D	3.2	1.3
TOTAL OUTPUT		194.3	80.3

VI. PLANT DEFINITION

The preliminary process design used for this study is based on processing lignite-type coal in an oxygen-blown LURGI pressure gasification system. The coal was assumed to gasify similarly to North Dakota lignite.

The Plant Elements forming the basis of this study and estimate are listed below:

Area	Description
1100	Gasification
1200	Shift Conversion
1300	SNG Gas Cooling
1310	NH_3 Gas Cooling
1400	SNG Rectisol and Refrigeration
1410	NH_3 Rectisol and Refrigeration
1420	Final CO_2 Wash (2nd Stage Rectisol) and Refrigeration
1600	Phenosolvan and Ammonia Recovery
1700	Methanation
1800	Gas Liquor Separation
1900	Product Gas Compression and Drying
2000	Coal Preparation and Handling
3000	Air Separation Unit
3100	Nitrogen Compression and Liquid Nitrogen Wash
3200	Ammonia Synthesis Loop
3300	Ammonia Refrigeration
4000	Sulfur Recovery
5000	Steam Generation and Distribution
5200	Stack Gas Scrubbing
5300	Power Distribution
5400	Raw Water Supply and Treating

VI. PLANT DEFINITION - Cont'd

Area	Description
5500	Cooling Water
5600	Fire Protection System
5700	Miscellaneous Utilities
6000	Offsite Storage and Loading Facilities
7000	Plant Interconnecting Piping
8100	Liquid Waste Effluent System
8200	Ash Disposal
8300	Flare System

VI. PLANT DEFINITION - Cont'd

A brief description of each area follows below:

Area 1100 - Gasification

The coal is gasified using a multiple train of LURGI pressure gasifiers. High-pressure oxygen and superheated steam are passed in countercurrent flow through a moving bed of coal, resulting in nearly complete conversion of the coal to gaseous compounds, some of which are subsequently condensed and processed in the liquid state.

Sized coal is conveyed from the coal storage to coal bunkers located above the gasifiers. Coal is charged to gasifiers through automatically operated coal locks which are depressured before receiving coal from the bunkers. The lock gas from depressuring is recompressed and re-injected in the gas cooling unit.

After filling with coal, the coal lock is pressurized with crude gas from the gas cooling unit and is equalized with the pressure of the gasifier. The coal is then charged to the top of the coal bed in the gasifier.

The gasification agent consisting of a mixture of oxygen and superheated steam is introduced through a rotating grate below the ash bed at the bottom of the gasifier. Partial combustion of the coal with the oxygen supplies the heat necessary for the gasification reactions.

Besides the crude gas produced, the process yields tar, oil, naphtha, phenols, ammonia, and sulfur.

The ash produced is removed by the rotating grate and discharged through a semi-automatically operated ash lock into an ash chute. From the ash chute, the ash is quenched with water and transferred to ash disposal.

Steam is generated in the jacket of the gasifier from the combustion heat and acts to cool the inner wall of the gasifier. The steam passes through a knock-out drum and is returned directly to the gasifier, partially furnishing the steam required for gasification.

The hot crude gas leaving the gasifier is directly quenched in a wash cooler with recycled tarry gas liquor. Tarry gas liquor produced in excess of the recycle is sent to the gas liquor separation unit.

The crude gas freed from dust and heavy condensibles and saturated with steam is further cooled by generation of 100 psig steam in a waste heat exchanger. The crude gas is then divided, with a portion passing directly to the gas cooling unit and the remainder is routed to the shift conversion unit.

VI. PLANT DEFINITION - Cont'd

Area 1200 - Shift Conversion

The shift conversion unit is designed to produce hydrogen required to raise the H_2/CO ratio for purposes of SNG production and ammonia synthesis. This is accomplished through the "water gas shift" reaction carried out catalytically in the presence of steam, as follows:

$$CO + H_2O = CO_2 + H_2 + 16{,}538 \text{ Btu/lb. mole.}$$

Approximately half of the total crude gas is subjected to shift conversion, with the balance bypassed directly to the gas cooling unit.

The portion of the converted gas used for SNG production is mixed with the bypass stream and passed to the gas cooling unit where additional heavy hydrocarbons and unreacted steam are condensed.

The proportions of these two streams are adjusted to obtain the desired H_2/CO of 3/1 ratio required for methanation.

The portion of the converted gas used for ammonia synthesis flows to a separate parallel gas cooling unit.

Area 1300 & 1310 - Gas Cooling Units

The gas cooling units are designed to cool the raw gas from gasification and shift conversion to remove the heavier hydrocarbons and unreacted steam before low-temperature purification. The cooling scheme is arranged to recover and utilize as much of the process heat as is practical.

First the converted gas is cooled and compressed. Following compression, the gas is divided into two portions. One portion is used for SNG production and mixes with cooled crude gas that bypasses the shift converters. Then it is cooled further in Area 1300.

The other portion used for ammonia synthesis is cooled in a parallel gas cooling train, provided in area 1310.

Area 1400, 1410, & 1420 - Rectisol Units

The gas purification unit utilizes the Rectisol process to remove CO_2, sulfur compounds, and other impurities from the raw gas. Low-temperature methanol is utilized to absorb the carbon dioxide and sulfur compounds. Sulfur compounds are removed to a level of less than 0.1 ppm (by volume) so that the gas meets the composition requirements for methanation.

The crude gas stream leaving the gas cooling units is chilled before entering the prewash tower to recover naphtha and water. The naphtha-free gas then enters an absorber, where sulfur compounds and the bulk of the CO_2 are removed by a cold methanol wash. The acid gas streams that leave the Rectisol System are directed to the Stretford unit for conversion to elemental sulfur.

VI. PLANT DEFINTION - Cont'd

Areas 1400, 1410 & 1420 - Rectisol Units - Cont'd

In Area 1400, the CO_2 in the SNG process stream is removed to about 3.5 mol percent, which is a suitable level for methanation. Similarly, most of the CO_2 is removed from the NH_3 process stream in Area 1410. However, the process gas for ammonia synthesis, has to be essentially free of CO_2; therefore, another CO_2 wash stage has been added in Area 1420.

Area 1600 - Phenosolvan and Ammonia Recovery Units

The process water from the Gas Liquor Separation Unit, which is contaminated with phenols, ammonia, hydrogen sulfide, and carbon dioxide, is treated in the Phenosolvan Unit prior to use as make-up water in the process gas liquor cooling tower. Crude phenol and liquid anhydrous ammonia byproducts are produced.

The incoming process water is passed through gravel filters for removal of suspended matter and then through extractors, where an organic solvent is used to extract phenols. The organic solvent is distilled and separated from the phenol and recycled to the extractors for reuse. The crude phenol by-product is recovered and transferred to storage for subsequent sale.

After removal of all traces of solvent, the dephenolized process water is stripped in the deacidifier to remove dissolved carbon dioxide and hydrogen sulfide, which is processed in the sulfur recovery unit. The resultant process water is distilled to recover 25 percent aqua ammonia, which is further distilled to produce commercially pure anhydrous ammonia. The remaining process water is then utilized as cooling water makeup to the process water cooling tower.

Area 1700 - Methanation

The methanation unit converts low BTU synthesis gas to methane-rich high BTU gas by the following exothermic reactions:

$$CO + 3H_2 = CH_4 + H_2O + 94{,}250 \text{ BUT per lb. mole } CH_4$$

$$CO_2 + 4H_2 = CH_4 + 2H_2O + 77{,}700 \text{ BTU per lb. mole } CH_4$$

Other minor reactions which take place are the hydrogenation of ethylene to ethane and hydrocracking of ethane to methane.

Process gas leaving SNG Rectisol unit is heated and passed through a guard vessel containing zinc oxide for removal of trace sulfur compounds. The flow of the feed gas is proportioned between two catalytic reactor stages along with recycled, methanated effluent gas, which serves to dilute the gas thereby controlling the temperature rise across the reactors. The reactors are designed as fixed bed downflow units employing a pelleted reduced nickel-type catalyst.

The reaction heat is removed by generation of 600 psig steam in waste heat exchangers at the outlet from each reactor.

VI. PLANT DEFINITION - Cont'd

Area 1700 - Methanation - Cont'd

Net gas leaving the methanation synthesis loop is passed through the cleanup reactor to accomplish essentially complete conversion of carbon monoxide, and then it is cooled by successive heat exchange with boiler feed water, fresh feed gas, air, and cooling water. Water condensed from the gas is separated and forwarded for recovery as boiler feed water. The net product is sent to the gas compression unit.

Area 1800 - Gas Liquor Separation

The gas liquor contains tar, tar oil, naphtha, and dissolved compounds such as phenols, ammonia, carbon dioxide, and hydrogen sulfide. Tar is defined as a heavier-than-water organic liquid phase, while tar oil is the lighter-than-water organic liquid phase.

The gas liquor separation is designed to clean up tarry and oily gas liquors by separating the incoming streams into tar, tar oil, recycled gas liquor, and clarified aqueous liquor streams.

The gas liquor streams originating from the gasification, shift conversion, and gas cooling units are cooled, combined, and reduced in pressure. The liquor flows to a large separator from which tar is removed. Flash gases released from the gas liquor by pressure reduction are scrubbed to remove ammonia. The tar is retained to be used as fuel within the plant or for export. The net liquor flow is forwarded to a second separator, where tar oil is separated and removed. The gas liquor passes to a final separator where additional tar oil is removed and sent to storage along with tar oil from the second separator.

The aqueous stream from the final separator passes to intermediate tankage before being fed to the Phenosolvan Unit.

Area 1900 - Product Gas Compression and Drying

The product gas compression unit consists of two parallel centrifugal compressors driven by condensing steam turbines. Gas leaving the methanation unit is compressed in the first stage of the compressor and then cooled prior to removing water to pipleline gas specifications. Drying is accomplished in a dehydration step employing liquid triethylene glycol (TEG) as the desiccant. The incoming wet product gas flows upward countercurrently with TEG in the glycol absorber. The dried product gas leaves the top of the absorber with a residual moisture content of less than 5 lbs./MM SCF of gas and passes to the second stage of compression. The water-rich TEG leaving the absorber bottom is passed to the glycol regenerator, where TEG is stripped of its water by heating with a small stream of dried product gas. The lean TEG from the glycol regenerator is returned to the top of the glycol absorber.

The product gas is then compressed in the second compression stage to the required pipeline pressure.

VI. PLANT DEFINITION - cont'd

Area 2000 - Coal Storage and Preparation

Run-of-mine coal is delivered to the plant. After crushing and screening, the coal is delivered through a system of conveyors to the live storage pile having a storage capacity of about six days' production for the gasification plant. A dead storage pile is also provided with a capacity sufficient to ensure approximately 30 days' production requirements. From the live storage pile, the coal is fed continuously through screens to achieve the correct size distribution for gasification. Coal fines not suitable for gasification are routed to storage silos and are used as fuel in the high-pressure steam boilers.

Area 3000 - Air Separation Unit

The oxygen facilities are designed to provide about 4000 T/D of gaseous oxygen to the process plant with an oxygen purity of 98 percent.

Two parallel process trains are utilized, with each unit consisting of a turbine-driven axial/centrifugal compressor, air separation section (cold box), and a turbine-driven centrifugal compressor. The air compressor turbines are of the extraction/condensing type, utilizing 1500 psig, 900°F steam from battery limits. The total make-up steam required for the rest of the complex is extracted at 550 psig, with the remainder going to the surface condensing type utilizing 550 psig steam.

Gasifier startup air and air for general use within the plant is provided from the air compressors. Excess nitrogen from the air separation system is used for the liquid nitrogen wash unit, ammonia synthesis, and process plant inert gas system. Liquid nitrogen storage is provided to ensure availability or purge gas during a plant outage.

Unit control will be centralized and combined with the main plant control room.

Area 3100 - Nitrogen Compression and Liquid Nitrogen Wash

Ammonia synthesis gas from the final CO_2 removal step goes to the liquid N_2 wash system. This gas first enters the washing column through a coil submerged in the liquid bottoms product. Most hydrocarbons and CO present in this stream condense, and the remainder of the gas, rich in hydrogen, enters the tower where residual hydrocarbons and CO are dissolved into circulating liquid nitrogen. The condensed hydrocarbon stream, identified as the methane fraction is first expanded and heated and then combined with the main SNG process stream going to the methanation unit. The purified hydrogen stream exiting the column overhead is mixed with addtional nitrogen to yield a H_2/N_2 ratio of 3/1. This mixture is heated by the incoming nitrogen and feed gas entering the liquid N_2 wash system and then is sent to the ammonia synthesis loop.

Another tail gas stream, identified as the fuel gas fraction, leaves the bottom of the column. This stream is available for use as fuel after being expanded and heated by incoming nitrogen.

VI. PLANT DEFINITION - Cont'd

Area 3100 - Liquid N2 Wash and N2 Compression - Cont'd

Nitrogen leaving the air separation unit is compressed to about 400 psig and cooled by the synthesis gas and the two expanded tail gas streams. Liquid nitrogen leaving the last exchanger is split in two portions. One portion enters the top of the washing column and is used as the scrubbing medium, while the other portion bypasses the column and is expanded and mixed with the purified hydrogen stream overhead stream to a H_2/N_2 ratio of 3/1.

The isenthalpic expansion of the nitrogen stream and the two tail gas streams provide the refrigeration requirements of the liquid N2 wash system.

Area 3200 - Ammonia Synthesis Loop

The H_2/N_2 mixture leaving the liquid N_2 wash system is first compressed to synthesis loop pressure of 2600 psig and then catalytically converted to ammonia according to the following reaction:

$$N_2 + 3H_2 \rightleftharpoons 2NH_3$$

This reaction is highly exothermic, and heat is recovered from the product stream by generating 600 psig steam preheating boiler feed water and feed effluent heat exchange. Further cooling and condensation of the ammonia product is achieved in water-cooled exchangers and refrigeration.

Refrigeration is provided by evaporating ammonia product and by an absorption/refrigeration package unit using lithium bromide. This system is used because of the available large quantities of low-pressure steam generated in the gas cooling section of the plant.

Uncondensed, unreacted hydrogen/nitrogen mixture is recompressed and recycled to the reactor. Condensed ammonia product is sent to storage tanks.

Area 4000 - Sulfur Recovery

The sulfur in the coal feed to the gasification plant is recovered using technologies based on the characteristics of each sulfur-containing stream produced in the plant. The design of the sulfur recovery system is based on coal containing an average of 0.93 percent sulfur on a DAF basis.

Most of the sulfur in the coal feed to the gasifiers is converted to hydrogen sulfide, which is removed from the crude gasifier effluent in the Rectisol system as a combination of acid gas streams. The hydrogen sulfide is converted in a Stretford unit to saleable elemental sulfur in liquid form.

The sulfur in the coal fines used to fire the steam boilers is converted to SO_2 and is removed from the flue gas leaving the boilers in a system consisting of electrostatic precipitators and a Wellman-Lord stack gas scrubbing unit described in Area 5200.

VI. PLANT DEFINITION - Cont'd

Area 4000 - Sulfur Recovery - Cont'd

The SO_2 is further converted to sulfuric acid, as described below.

Stretford Unit

The Stretford process, licensed by the North West Gas Board of the British Gas Corporation, is used to recover elemental sulfur from the combined acid gas streams leaving the Rectisol system. The process, using a dilute aqueous solution containing Na_2CO_3 sodium meta-vanadate and anthraquinone disulfonic acid (ADA), operates in a continuous, regenerative fashion, as follows:

H_2S is absorbed from the gas by the alkaline carbonate solution forming HS^- ions. This is accomplished in a countercurrent open grid tower. The sulfide is oxidized to free sulfur by vanadate according to the reaction:

$$HS^- + 2V^{5+} \rightleftharpoons 2V^{4+} + S + H^+$$

This reaction proceeds during the absorption step and is completed in a holding vessel. The solution is regenerated by reoxidation of V^{4+} to V^{5+}. This is accomplished by sparging with air in a separate vessel with ADA acting as a catalyst for the reaction. The sulfur forming as a floating froth is separated from the solution and is processed to produce a saleable liquid sulfur by-product.

The Stretford process removes only sulfur in the form of H_2S. Other sulfur compounds such as COS, CS_2, and mercaptans are unaffected by the process. The sulfurous compounds are present only in small concentrations and are incinerated to SO_2 at the Thermal Generating Station. A small degree of oxidation of sulfides in solution to thiosulfate and sulfate occurs. These salts are non-regenerable and require a small liquid purge.

The unit is designed in two parallel trains, each with a nominal capacity of 50 percent.

SO2 Conversion

The SO_2 stream leaving the Wellman-Lord system described in Area 5200 flows to a catalytic converter, where conversion of sulfur dioxide to sulfur trioxide takes place over vanadium pentoxide catalyst according to the following reaction:

$$2SO_2 + O_2 \rightleftharpoons 2SO_3$$

VI. PLANT DEFINITION - Cont'd

Area 4000 - Sulfur Recovery - Cont'd

SO_2 Conversion - Cont'd

Sulfur trixoide leaving the converter flows to an absorption tower, where it is absorbed in a strong aqueous solution of sulfuric acid. Additional sulfuric acid, resulting in a higher H_2SO_4 concentration, is formed due to the following reaction:

$$SO_3 + H_2O \rightleftharpoons H_2SO_4$$

Dilution water is added to the H_2SO_4 circulation system to maintain a steady concentration level, and an acid slip stream withdrawn from the absorber overhead is sent to the H_2SO_4 product storage facilities.

Area 5000 - Steam Distribution

Steam generated at 1500 psig and 900°F is let down through extraction condensing turbines driving the air compressors in the air separation unit. The 550 psig steam for the air compressor turbines is combined with 600 psig steam generated in the methanation and ammonia synthesis loop waste heat boilers. This steam is supplied to the gasifiers and to turbine drivers fed from the 550 psig steam system. The oxygen, refrigeration, ammonia synthesis, nitrogen, and product gas compressor Turbines use 550 psig and 100 psig steam, discharging to condensers at 4" Hga.

Steam generated from waste heat in the gasification unit is fed to the 100 psig steam system. This steam is used for reboilers in the Phenosolvan, Rectisol, and Stretford units, steam jet air ejectors, lock gas compressors, converted gas booster compressor, and methanation recycle compressors. These turbines all exhaust to condensers at 4" Hga.

Steam generated from the heat recovered in the shift conversion waste heat boilers and some of the gas cooling waste heat boilers is fed to the 60 psig steam system. This steam is utilized as heat input to reboilers in the Phenosolvan and Rectisol areas and for steam tracing and tank heaters. Excess steam from the 60 psig steam system is let down into the 20 psig header. The remaining gas cooling waste heat boilers generate additional 20 psig steam to be used as heating steam for reboilers in the Phenosolvan, Rectisol, NH_3 refrigeration and stack gas scrubbing units, and for the plant deaerators.

Turbine condensate, condensate from the 20 psig and 60 psig steam levels, makeup water from battery limits, and 20 psig steam are mixed and deaerated in the MP deaerator. The MP boiler feed pumps provide feed water to the gasifier jackets and to the methanation waste heat boilers through process exchangers.

Low-pressure condensate, make-up from battery limits, blowdown water, and 20 psig steam are mixed and deaerated in the LP deaerator. The 100 psig boiler feed pumps take suction from the deaerator and pump the feed water through process exchangers to the gasification waste heat boilers. The LP boiler feed pumps take suction from the deaerator and provide feed water to the shift conversion and gas cooling waste heat boilers.

VI. PLANT DEFINITION - cont'd

Area 5000 - Steam Distribution - cont'd

Turbine condensate, condensate from the 600 psig and 100 psig levels, and 20 psig steam are mixed and deaerated in the HP deaerator. The HP boiler feed pumps take suction from the deaerator and provide feed water to the shift conversion and gas cooling waste heat boilers.

Turbine condensate, condensate from the 600 psig and 100 psig levels, and 20 psig steam are mixed and deaerated in the HP deaerator. The HP boiler feed pumps take suction from the deaerator and provide feed water to the HP steam generation system.

Area 5200 - Stack Gas Scrubbing

This study is based on using excess coal fines produced in the coal preparation area as fuel for generating the steam requirements of the complex.

The coal fines fired in the steam boilers contain .93 wt. percent sulfur on a DAF basis. This results in about 1.3 lbs. of sulfur dioxide in the flue gas per MM BTU (HHV) of coal fines fired. A portion of this flue gas is scrubbed by the Wellman-Lord SO_2 recovery system in order that the SO_2 emission level in the stack gas can be reduced to no more than 1.2 lbs. of SO_2 per MM BTU (HHV) of coal fines fired. This maximum SO_2 emission level is specified by the Federal Environmental Protection Agency.

The Wellman-Lord system employs a process which continuously absorbs and regenerates SO_2 using an aqueous solution of sodium sulfite and sodium bisulfite. The reactions are:

Absorption: $$SO_2 + Na_2SO_3 + H_2O \rightleftharpoons 2NaHSO_3$$

Regeneration: $$2NaHSO_3 \rightleftharpoons Na_2SO_3 + SO_2 + H_2O$$

The flue gas feed to the Wellman-Lord system flows upward in an SO_2 absorber against an aqueous solution of sodium sulfite. With SO_2 removed, the flue gas leaves the top of the absorber and is discharged to the stack.

Sodium bisulfite solution containing SO_2 exits from the absorber into a forced-circulation evaporator-crystallizer, which is heated by low-pressure exhaust steam. The SO_2 vapor from the evaporator-crystallizer is cooled to remove water and then is sent to the sulfur recovery area.

The sulfite crystallizes in the evaporator-crystallizer and changes the solution to a sulfite slurry. The slurry is passed to a dissolving tank, where sulfite crystals are re-dissolved by water from the SO_2 vapor. The resultant solution is used again in the SO_2 absorber.

A moderate amount of the circulating solution is oxidized to non-regenerable sulfate. To control the sulfate level, a small stream of the solution is purged from the system and sent to the deep well disposal system.

VI. PLANT DEFINITION - cont'd

Area 5300 - Power Distribution

A conventional 3-level distribution system for an estimated total requirement of 58,000 KW is included in the design.

Area 5400 - Raw Water Supply & Treating

Raw water is supplied at the Gasification Plant battery limits. The sequence of water treating steps and the interaction with the waste effluent steps are similar to those shown on Sketch No. 4, Water Management Diagram. The system was designed for maximum water reuse. Raw water is required for cooling tower and potable water makeup.

Area 5500 - Cooling Water

Three separate cooling towers are provided to handle the bulk of the plant heat rejection, as follows:

- Cooling tower using treated fresh water as makeup.

- Cooling tower using treated gas liquor (process water) from the Phenosolvan and Gas Liquor Stripping Unit as makeup.

- Separate cooling tower using treated fresh water for the oxygen plants in order to minimize the hazard associated with hydrocarbons entering this system.

Blowdown water from the process gas liquor cooling tower system will be disposed of, conforming to local environmental regulations.

Chemical feeding equipment will be provided to permit addition of water treating chemicals to all systems as required in order to adjust pH and inhibit corrosion, scale formation, and biological plant growth.

Area 5600 - Fire Protection System

The fire protection system consists of a fire water loop, chemical, and foam fire suppression equipment and mobile equipment.

Area 5700 - Miscellaneous Utilities

Potable Water

Water for the potable and sanitary use is supplied from the raw water treatment plant where it is filtered, chlorinated, and treated prior to distribution.

VI. PLANT DEFINITION - cont'd

Area 5700 - Miscellaneous Utilities - cont'd

Instrument Air, Plant Air, and Inert Gas

A plant air system is provided to supply compressed air at a nominal 100 psig pressure to shops and service outlets throughout the plant.

Plant air is normally supplied from the air separation plant main air compressors. During periods of total plant shutdown, motor-driven air compressors supply the plant air requirements. The system is complete with necessary after-coolers, air receivers, and distribution piping. All plant air will be dried.

An instrument air system is provided to supply clean, dry air for instrument operation.

Instrument air is supplied by oil-free, motor-driven compressors operating at a system pressure of 100 psig. The system is complete with dryers, air receivers, and distribution piping. To ensure maximum reliability during a power outage, these compressors are connected to the emergency power system.

An inert gas system is provided to supply dry nitrogen from the oxygen plant. In addition, a liquid nitrogen tank provided with vaporization facilities supplies nitrogen to the system during periods of oxygen plant outage.

Communications

The plant is provided with two communication systems. An in-plant dial telephone system is installed and operated by the telephone company in space provided by the plant. This arrangement avoids capital expenditure and hiring of specialized maintenance skills. The system is automatically monitored against failure to the degree that it is acceptable for fire reporting and thereby avoids the operation of a separate fire alarm system. The system is arranged to allow outside communication from designated telephones.

Operating communications throughout the plant to roving personnel and vehicles is by radio. Radio paging interconnected with the telephone system is included for contacting non-operating personnel when they are away from their normal stations.

Area 6000 - Offsite Storage and Loading Facilities

Storage facilities are included to store by-products in the plant. Storage for a number of raw materials for plant feed are also provided. A minimum of 15-days' storage supply is provided for most by-products and raw materials, except for the anhydrous ammonia storage tank, where 30-days' storage is provided. The anhydrous ammonia product is stored as a liquid at atmospheric pressure in a double-wall insulated tank with a vapor recovery refrigeration system.

Liquid elemental sulfur produced in the sulfur recovery plant is pumped from a heated sulfur pit included in the sulfur recovery unit to the stockpile area.

VI. PLANT DEFINITION - cont'd.

Area 8100 - Liquid Waste Effluent System

The liquid waste effluent treatment system is designed to maximize water reuse. The only discharge of waste water from the plant is cooling tower blowdown going to disposal and the water associated with the ash handling facility returning to the mine. The effluent treatment scheme is similar to that shown on the Water Management Diagram Sketch No. 4.

The bulk of reusable water is derived from the gas liquor area. After most of the phenols are extracted and H_2S, CO_2, and NH_3 are stripped from this stream, the process condensate is used as make-up water for the process gas liquor cooling tower. The cooling tower also serves as an oxidation unit for reduction of biological and chemical oxygen demand.

The blowdown from the process gas liquor cooling tower will be pretreated and disposed of, conforming to local environmental regulations.

Area 8200 - Ash Disposal

Ash discharged from the gasifiers is quenched and sluiced by water to screw classifiers. The classifier discharge drops onto conveyors and is transferred to an ash bin, which is emptied into trucks for disposal in the mining area.

Area 8300 - Flare System

The flare system will be capable of flaring the total gasifier effluent in the event of power failure, steam system, or cooling water failure. A knock-out drum will be provided to collect any water and heavy hydrocarbons in the gasifier effluent that may condense en route to the flare. These liquids will be incinerated. The flare system may also be employed to flare product gas during plant startup when gas quality is below the acceptable specifications.

The flare system will collect all emergency and operating hydrocarbon vents and burn them at the top of a flare stack.

The self-supporting flare stack includes ignitor, flame front generators, molecular seal, and continuous burning pilots. Ladder and access platforms will be provided on the flare stack to facilitate maintenance.

VII. ENVIRONMENTAL CONSIDERATIONS

The environmental control systems integrated with the process units and the cooling water, steam generation, and ash handling systems are designed to meet applicable environmental standards and regulations.

Air Emission

Sulfur Dioxide Emission

The sulfur in the coal feed to the gasifiers and the steam boilers is recovered to a major extent. After being cleaned and cooled, the raw product gas is passed through a Stretford desulfurization system. Virtually all the hydrogen sulfide in the gas is converted to elemental sulfur and removed.

The flue gas from steam boilers is scrubbed in the Wellman-Lord SO_2 recovery system described in Area 5200. The coal fines fired in the boiler result in about 1.3 lbs. of SO_2 per MM BTU fired. The flue gas from the Wellman-Lord system contains less than 1.2 lbs. of SO_2 per MM BTU FIRED and is discharged to the stack.

Oxides of Nitrogen

The formation of oxides of nitrogen (NOx) depends on the size, type, and arrangement of burners, type of fuel, and the heat flux. The steam boilers will be designed to limit the NOx formation to a level below that permitted by the EPA.

Flare

Vent gas deriving from startup, emergency blowdown, and temporary local relief is sent via headers to an elevated flare system.

Particulates

The flue gas from the steam boilers will be passed through electrostatic precipitators, which will remove about 99 percent of the fly ash. Secondary cleaning and polishing are done in the Wellman-Lord system. The resulting particulate emission after the cleanup will be below the level permitted by the EPA.

Effluent Water Streams

Process and utility waste water will be reused within the plant to minimize discharge to the river.

The process gas liquor is treated to remove oils, phenols, ammonia, and hydrogen sulfide. The stripped gas liquor is then used as the make-up water for the process water cooling tower. The blowdown from this cooling tower is treated to remove suspended matter and is then sent to disposal. The blowdown

from the fresh water cooling tower is treated to remove any contaminants and may be reused in the humidifier section of the Wellman-Lord unit.

Solids Removal

Ash and other solid wastes will be sent to the mine. Certain aqueous waste streams could be disposed of with the ash. Ash leachability studies and methods of preventing contamination of water in nearby wells should be considered.

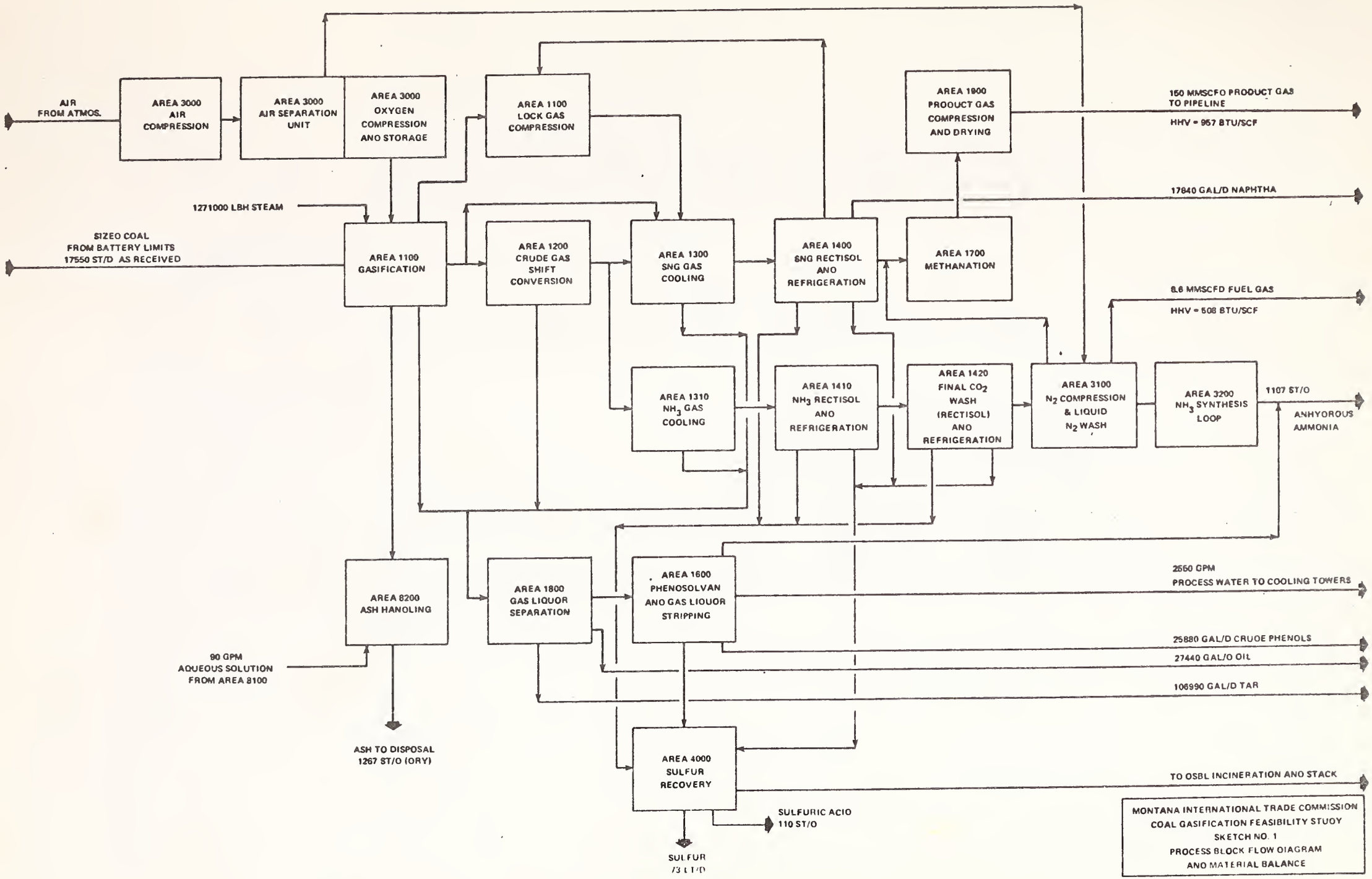
Socio-Economic Considerations

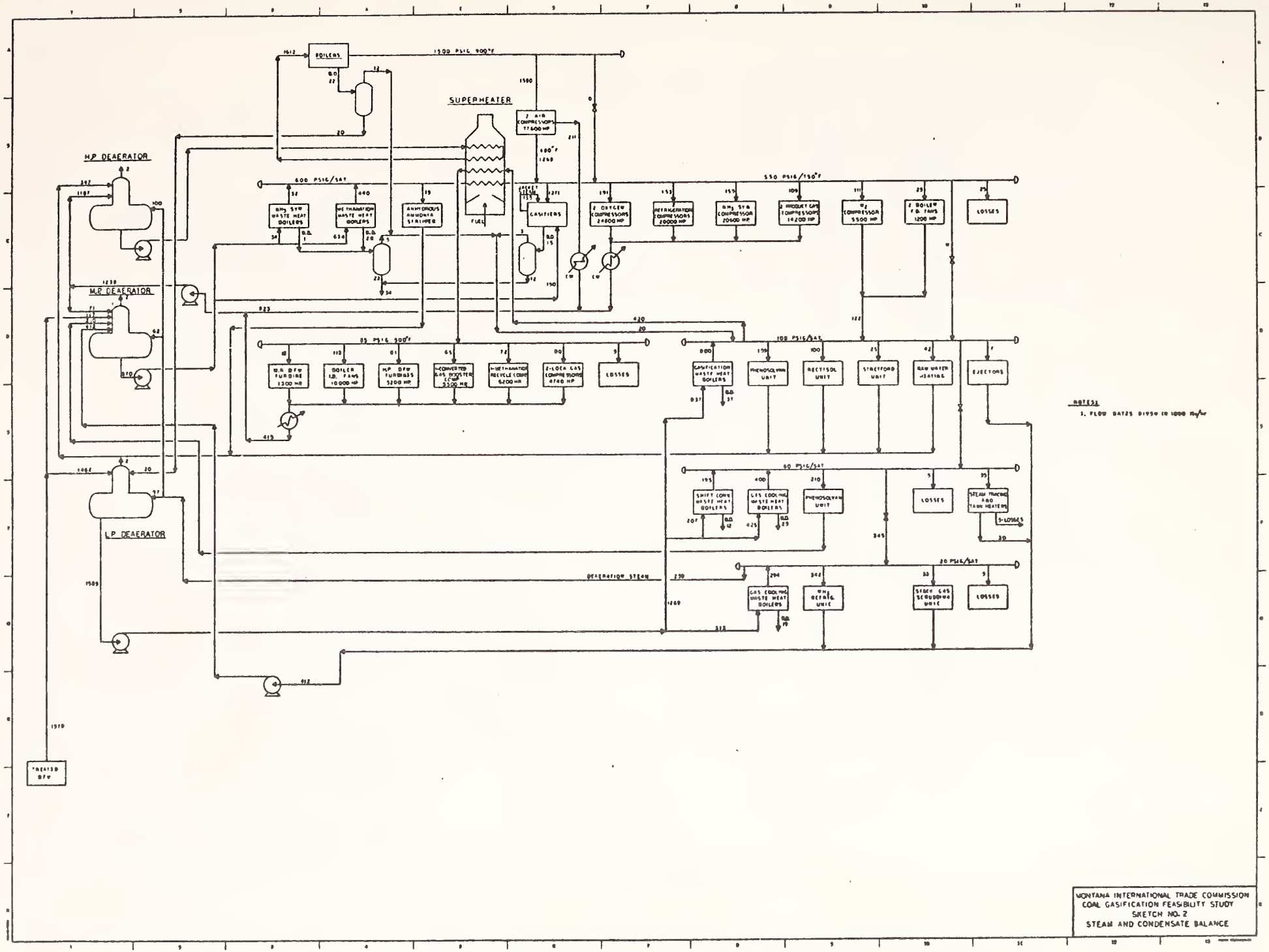
During the construction of the plant, a work force of some 2000-3000 people, not including support facilities, will be employed. The socio-economic and environmental impact of these people and the related housing, transportation, sanitary, recreational facilities, etc., must be taken into account.

VIII. APPENDIX

Sketches

NO. 1 -	Process Block Flow Diagram and Material Balance
NO. 2 -	Steam and Condensate Balance
NO. 3 -	Cooling Water Balance
NO. 4 -	Water Management Diagram
NO. 5 -	Process Train Arrangement Diagram
NO. 6 -	Overall Plant Layout and Space Requirements

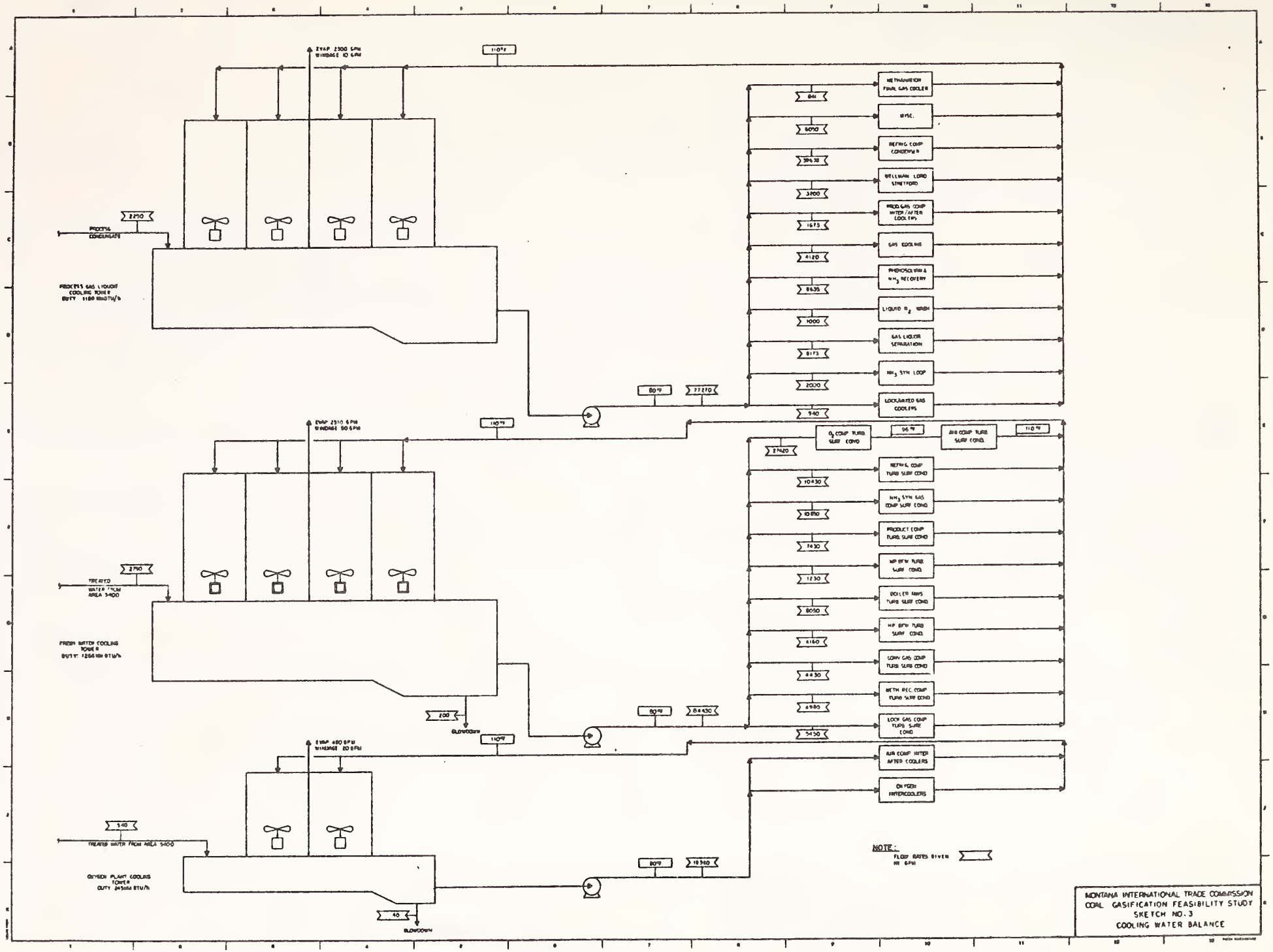

AIR FROM ATMOS.
AREA 3000 AIR COMPRESSION
AREA 3000 AIR SEPARATION UNIT
AREA 3000 OXYGEN COMPRESSION AND STORAGE
AREA 1100 LOCK GAS COMPRESSION
AREA 1900 PRODUCT GAS COMPRESSION AND DRYING
150 MMSCFD PRODUCT GAS TO PIPELINE
HHV = 967 BTU/SCF
17840 GAL/D NAPHTHA
1271000 LBH STEAM
SIZED COAL FROM BATTERY LIMITS 17550 ST/D AS RECEIVED
AREA 1100 GASIFICATION
AREA 1200 CRUDE GAS SHIFT CONVERSION
AREA 1300 SNG GAS COOLING
AREA 1400 SNG RECTISOL AND REFRIGERATION
AREA 1700 METHANATION
8.6 MMSCFD FUEL GAS
HHV = 508 BTU/SCF
AREA 1310 NH_3 GAS COOLING
AREA 1410 NH_3 RECTISOL AND REFRIGERATION
AREA 1420 FINAL CO_2 WASH (RECTISOL) AND REFRIGERATION
AREA 3100 N_2 COMPRESSION & LIQUID N_2 WASH
AREA 3200 NH_3 SYNTHESIS LOOP
1107 ST/D
ANHYDROUS AMMONIA
AREA 8200 ASH HANDLING
AREA 1800 GAS LIQUOR SEPARATION
AREA 1600 PHENOSOLVAN AND GAS LIQUOR STRIPPING
2560 GPM
PROCESS WATER TO COOLING TOWERS
25880 GAL/D CRUDE PHENOLS
27440 GAL/D OIL
106990 GAL/D TAR
90 GPM AQUEOUS SOLUTION FROM AREA 8100
ASH TO DISPOSAL 1267 ST/D (DRY)
AREA 4000 SULFUR RECOVERY
TO OSBL INCINERATION AND STACK
SULFURIC ACID 110 ST/D
SULFUR 73 LT/D
MONTANA INTERNATIONAL TRADE COMMISSION
COAL GASIFICATION FEASIBILITY STUDY
SKETCH NO. 1
PROCESS BLOCK FLOW DIAGRAM AND MATERIAL BALANCE

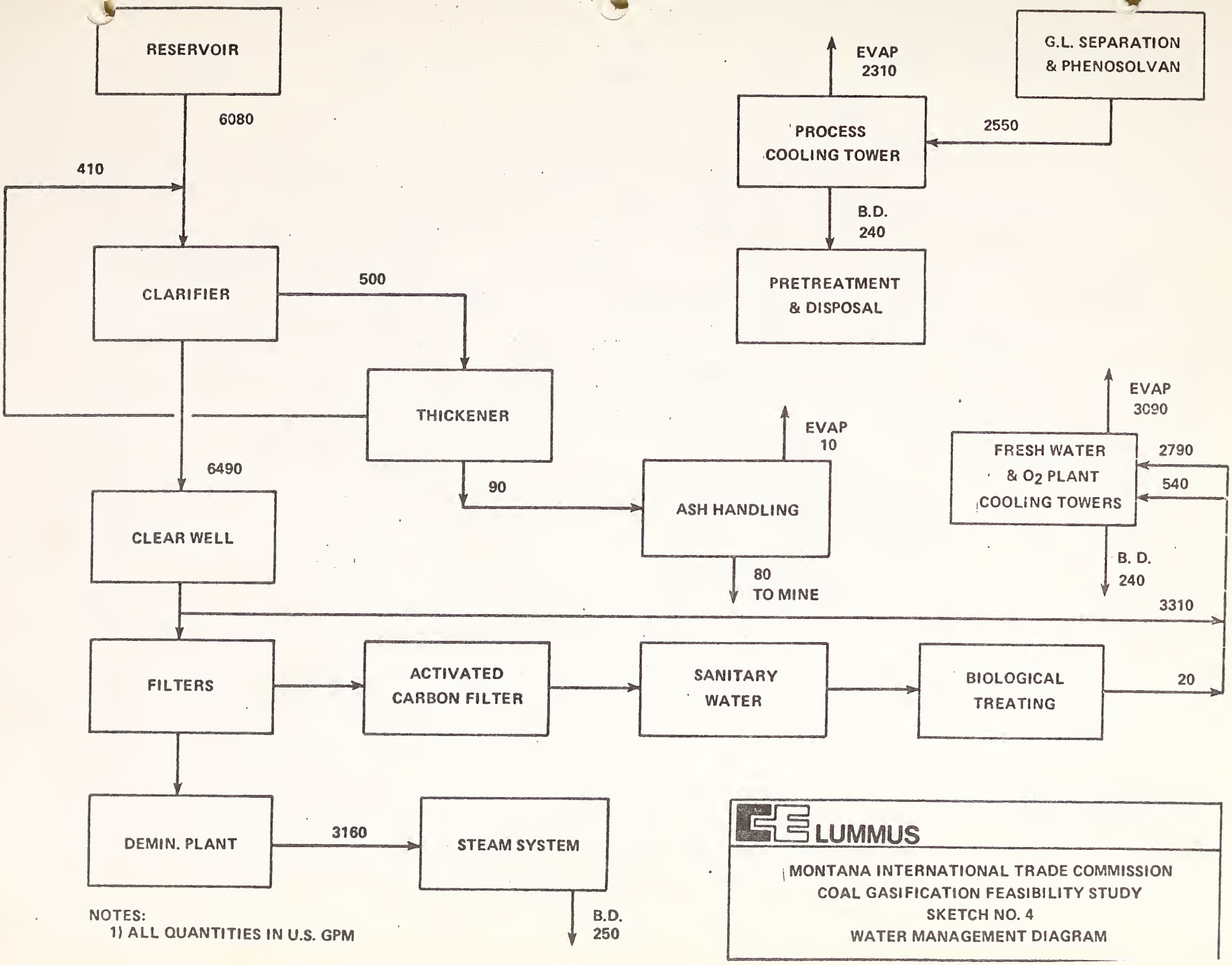


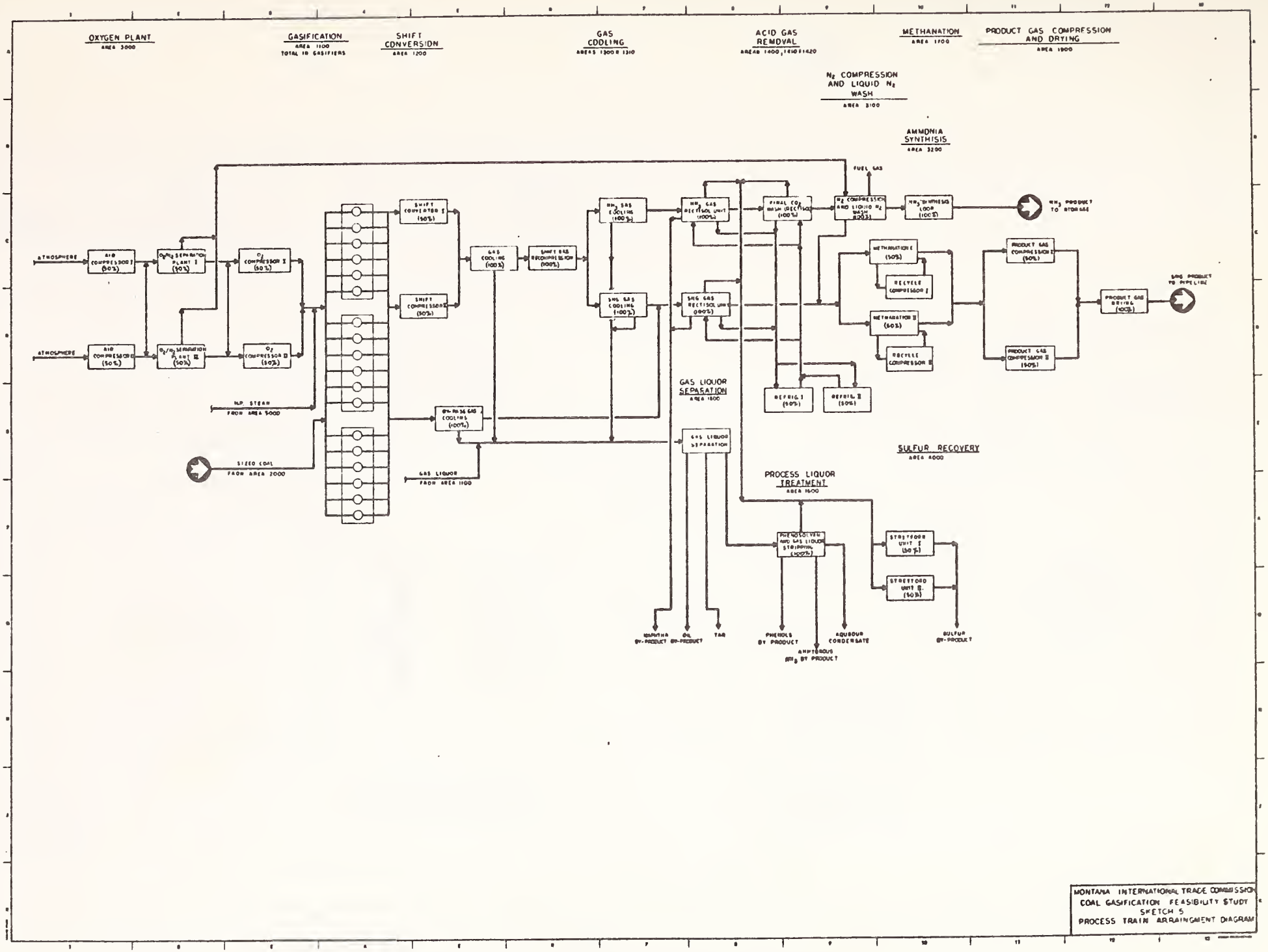
NOTES:

1. FLOW RATES DIFFER IN 1000 lb/hr

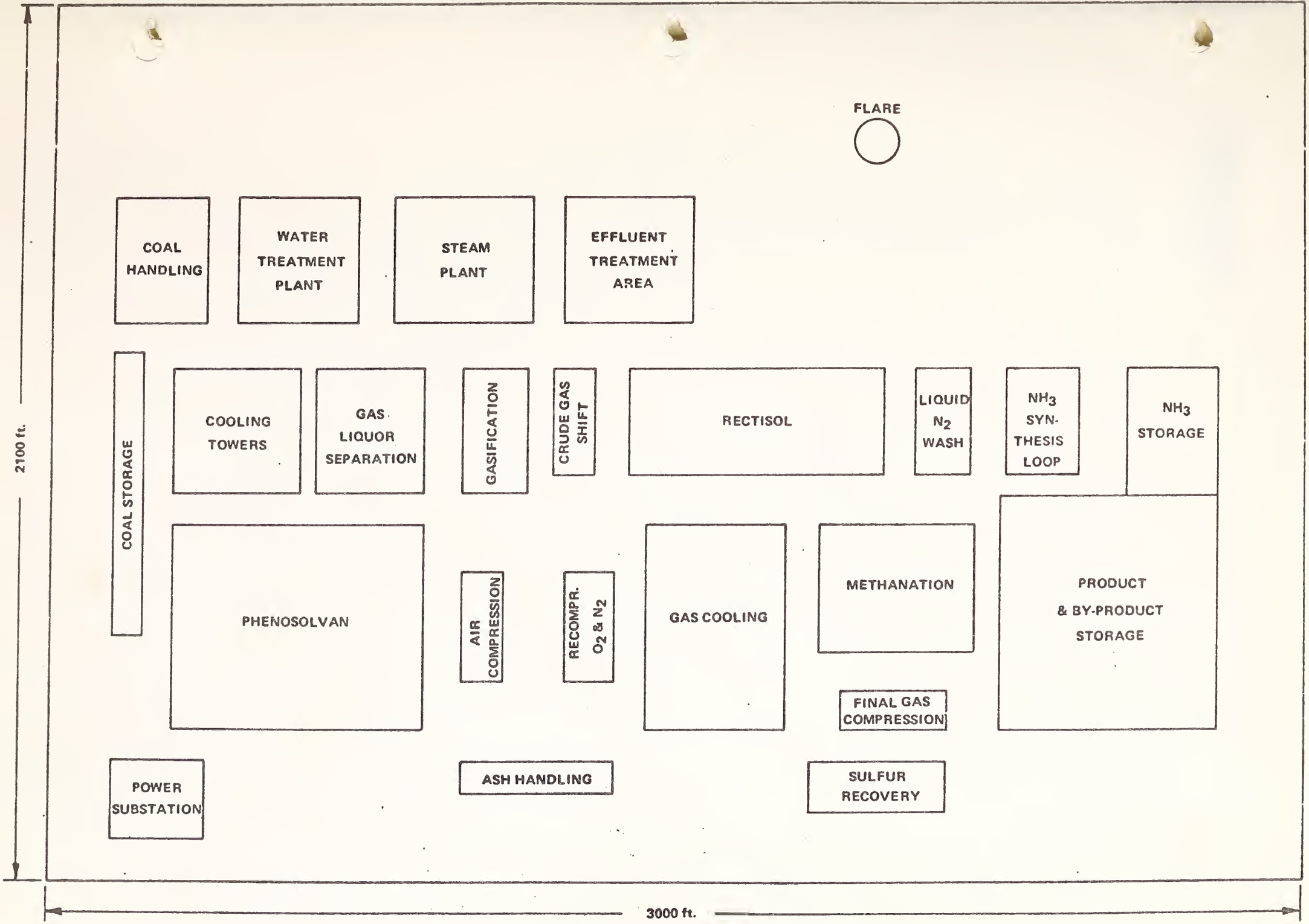
MONTANA INTERNATIONAL TRADE COMMISSION
COAL GASIFICATION FEASIBILITY STUDY
SKETCH NO. 2
STEAM AND CONDENSATE BALANCE


EVAP 2300 GPM
WINDAGE 10 GPM
110°F
2250
PROCESS CONDENSATE
PROCESS GAS LIQUOR COOLING TOWER
DUTY 1189 MMBTU/h
841
6050
394.30
3200
1675
4120
8635
1000
8175
2000
940
METHANATION FINAL GAS COOLER
MISC.
REFRIG COMP CONDENSER
BELLMAN LORD STRETFORD
PROD GAS COMP INTER/AFTER COOLERS
GAS COOLING
PHENOSOLVAN & NH_3 RECOVERY
LIQUID N_2 WASH
GAS LIQUOR SEPARATION
NH_3 SYN LOOP
LOCK/WASHED GAS COOLERS
80°F
77270
EVAP 2510 GPM
WINDAGE 50 GPM
110°F
27420
O_2 COMP TURB SURF COND
95°F
AIR COMP TURB SURF COND
110°F
10430
10850
7430
1230
8050
4160
4430
6980
5450
REFRIG COMP TURB SURF COND
NH_3 SYN GAS COMP SURF COND
PRODUCT COMP TURB SURF COND
MP BFW TURB SURF COND
BOILER FANS TURB SURF COND
HP BFW TURB SURF COND
CONV GAS COMP TURB SURF COND
METH REC COMP TURB SURF COND
LOCK GAS COMP TURB SURF COND
2710
TREATED WATER FROM AREA 5400
FRESH WATER COOLING TOWER
DUTY: 1256 MM BTU/h
200
BLOWDOWN
80°F
84430
EVAP 480 GPM
WINDAGE 20 GPM
110°F
AIR COMP INTER AFTER COOLERS
OXYGEN INTERCOOLERS
540
TREATED WATER FROM AREA 5400
OXYGEN PLANT COOLING TOWER
DUTY 245MM BTU/h
40
BLOWDOWN
80°F
18360
NOTE:
FLOW RATES GIVEN IN GPM
MONTANA INTERNATIONAL TRADE COMMISSION
COAL GASIFICATION FEASIBILITY STUDY
SKETCH NO. 3
COOLING WATER BALANCE


RESERVOIR
6080
410
CLARIFIER
500
THICKENER
90
6490
CLEAR WELL
EVAP
10
ASH HANDLING
80
TO MINE
EVAP
2310
PROCESS
COOLING TOWER
2550
G.L. SEPARATION
& PHENOSOLVAN
B.D.
240
PRETREATMENT
& DISPOSAL
EVAP
3090
FRESH WATER
& O2 PLANT
COOLING TOWERS
2790
540
B. D.
240
3310
FILTERS
ACTIVATED
CARBON FILTER
SANITARY
WATER
BIOLOGICAL
TREATING
20
DEMIN. PLANT
3160
STEAM SYSTEM
B.D.
250
NOTES:
1) ALL QUANTITIES IN U.S. GPM
LUMMUS
MONTANA INTERNATIONAL TRADE COMMISSION
COAL GASIFICATION FEASIBILITY STUDY
SKETCH NO. 4
WATER MANAGEMENT DIAGRAM



MONTANA INTERNATIONAL TRADE COMMISSION
COAL GASIFICATION FEASIBILITY STUDY
SKETCH 5
PROCESS TRAIN ARRAINGMENT DIAGRAM



MONTANA INTERNATIONAL TRADE COMMISSION
COAL GASIFICATION FEASIBILITY STUDY
SKETCH NO. 6 - OVERALL PLANT LAYOUT AND SPACE REQUIREMENTS

Dravo

APPENDIX E

A PERFORMANCE SPECIFICATION FOR OBTAINING A CONCEPTUAL DESIGN OF A COAL GASIFICATION PLANT FOR THE STATE OF MONTANA

INDEX

Dravo

A PERFORMANCE SPECIFICATION FOR OBTAINING A CONCEPTUAL DESIGN OF A COAL GASIFICATION PLANT FOR THE STATE OF MONTANA

1.0 GENERAL SCOPE

The offeror is to submit to the state of Montana a proposal for the engineering services necessary to provide a conceptual commercial design and evaluation of a coal gasification facility.

The proposed Montana lignite coal gasification commercial plant is to produce 85 MM SCFD of pipeline-quality gas.

The site of the facility is tentatively located at the Glasgow Air Force Base located in northeastern Montana, in Valley County, 42 miles south of the U.S.-Canadian border.

The facility shall be a complete grass roots plant processing run-of-mine lignite coal, with type Circle West lignite "R" Bed or equivalent as the design feed. The mine location will be approximately 40 miles S/SE Glasgow Air Force Base. Lignite delivery to the facility will be by unit train. It should be assumed for design that water will be available from the Missouri River to satisfy the requirements for make-up water.

The plant must include all facilities necessary for a self-sustaining operation except that electrical power requirements for the plant will be supplied by a local utility company. The plant must be designed on the basis of minimizing electrical power requirements.

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2.0 PROCESS REQUIREMENTS

2.1 Acceptable Gasification Processes

The conceptual design shall be based on using the Lurgi gasification process or other process as selected by Montana Trade Commission, as specified in the transmittal letter.

2.2 Product Gas Capacity

The proposed commercial plant shall produce 85 million SCFD of Substitute pipeline gas.

2.3 Design Feed Coal Composition and Size

Type - Circle West Lignite "R" Bed

Mine Location - 40 miles S/SE Glasgow Air Force Base

Proximate Analysis

Weight % as received

Moisture	35.02
Volatile Matter	26.45
Fixed Carbon	31.67
Ash	6.86

Ultimate Analysis

(Dry) Weight % Ash Free

Carbon	71.68
Hydrogen	5.59
Nitrogen	1.03
Oxygen	21.75
Combustible Sulfur	0.93
Chlorine	0.02

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2.0 PROCESS REQUIREMENTS (Cont'd.)

2.3 Design Feed Coal Composition and Size (Cont'd.)

Heating Value as Received	6,894 Btu/lb
Heating Value Dry	10,610 Btu/lb
Ash Fluid Temperature	
Red.	2350°F
Ox.	2390°F
Size	2" x 0"
Method of Delivery	Unit Train

2.4 Product Gas Quality and Condition

The product gas from the coal gasification plant is to be dried (7 lbs. of water/MM SCF), compressed and delivered to a transmission pipeline at the plant site boundary at 1000 psig. The product gas shall have a minimum purity of 90-91 volume % methane and a heating value of 925 + Btu/SCF (HHV, dry). Contaminants shall not exceed 0.1 volume % carbon monoxide; 0.25 grains hydrogen sulfide/100 SCF product gas; and 10 grains total sulfur/100 SCF product gas.

2.5 By-Products Quality

2.5.1 Anhydrous Ammonia - ammonia if produced in the gasifiers and recovered as anhydrous ammonia shall have an impurity level of lower than 10 grains sulfur/100 SCF.

2.5.2 Sulfur - If the product is recovered for sale, the purity shall be 99.8%, and shall be delivered as flakes.

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2.0 PROCESS REQUIREMENTS (Cont'd.)

2.5 By-Products Quality (Cont'd.)

2.5.3 Liquid hydrocarbons shall meet commercial specifications if practical. If such specifications are not available, materials produced shall be sufficiently defined (chemical and physical analysis) to permit marketability studies.

2.6 Turndown

The plant shall be designed to operate satisfactorily at 25% of its rated capacity unless this level of operation cannot be obtained by the gasifier selected.

2.7 On-Stream Factor

The on-stream factor shall be 90%.

2.8 Feedstock Flexibility Requirements

While the design feed to the gasifier is to be Circle West Lignite "R" Bed, the gasifier should be able to handle other coals such as area "E" McKay seam, Circle West "S" Bed, and Red Water Lignite.

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3.0 CONTRACTOR'S SCOPE OF WORK

This specification covers the various items that must be included by the conceptual design contractor in describing the details of a conceptual design.

3.1 Block Flow Diagrams

On this project it is required for the contractor to prepare overall material and energy balance flow diagrams. On such diagrams, an entire processing step or area may be represented by a single labeled block. The material and energy balance quantities are shown on the lines connecting the blocks. This type of drawing supplements the process flow diagrams but does not replace them.

3.2 Process Flow Diagrams with Material and Heat Balances

The basic purposes of the process flow diagram are: 1) to present an overall process flow scheme of the entire plant; 2) to indicate quantities and components of all major process streams; 3) to indicate operating conditions at various points in the system; and 4) to define all utility systems.

All major process equipment is shown in simplified form, except that where identical units operate in parallel, only one unit is shown.

3.3 Preliminary Piping and Instrumentation Diagrams

The preliminary piping and instrumentation diagrams shall show all major equipment, instrumentation, and interconnecting piping in sufficient detail to define the process, and to provide a basis for the design work that is to be performed. The preliminary piping and

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3.0 CONTRACTOR'S SCOPE OF WORK (Cont'd.)

3.3 Preliminary Piping and Instrumentation Diagrams (Cont'd.)

instrumentation diagrams will define the instrumentation systems for the process.

3.4 Utility Balance Flow Diagrams

The basic purpose of the utility balance is to present a detailed summary of the plant utility requirements to permit the design of distribution and collection systems.

Utilities shall be considered fluids which are widely distributed or collected throughout the plant. These diagrams include materials such as steam, condensate, cooling water, process water, plant air, instrument air, inert gas, fuel gas, fuel oil, and vent streams.

3.5 Preliminary Equipment Specifications

Preliminary equipment specifications are documents prepared by the conceptual design contractor that describe individual items of equipment in sufficient detail to define the equipment selected in type, size, and capacity, and to obtain an estimated price.

3.6 Description of Process

The description of process is an engineering document prepared by the contractor which defines the process design basis, describes the operation of the plant, and also contains process information required by the design engineering groups but which cannot be conveniently transmitted on flow diagrams or equipment specifications. This may involve special considerations for startup, shutdown, handling of off-grade material, emergencies, hazards, future expansion, controls and interlocks, etc.

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3.0 CONTRACTOR'S SCOPE OF WORK (Cont'd.)

3.7 Item List

The contractor shall prepare an equipment item list which identifies all of the equipment required for the facility. This item list shall be segregated by plant or operating areas.

3.8 Conceptual Layout

Conceptual layouts and a plot plan shall be supplied by the contractor. The conceptual layouts shall be by plant or operating area and shall include both plan and elevation drawings. The plot plan shall indicate each area plus all other facilities required for a complete facility on the selected site.

3.9 Electrical

The contractor shall prepare electrical single-line diagrams and a general specification defining the electrical power requirements and distribution system for the complete facility.

3.10 General Specifications

The contractor shall prepare general specifications to define the design bases for the proposed facility and to establish the basis for estimating the capital cost of the facility. In addition, the electrical specification referred to in 3.9 above, General Specifications will be required for Instrumentation, Piping, Plumbing, Civil Structural, Architectural, Insulation, Painting, HVAC, and any others that may be applicable.

3.11 Capital Cost Estimate

The contractor shall prepare an estimate of the capital cost of the facility as presented in the conceptual design. The estimate will be

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3.0 CONTRACTOR'S SCOPE OF WORK (Cont'd.)

3.11 Capital Cost Estimate (Cont'd.)

based on current dollars and shall have an accuracy of ± 20%. The estimate shall be broken down by plant or operating areas in sufficient detail to be able to identify the cost of equipment items and components, materials, labor, sub-contracts, engineering, site development, and any other categories as determined by the state of Montana. Sources of costs are to be identified, as vendor quote, or in-house data, etc.

3.12 Operating Cost Estimate

The contractor shall prepare an operating cost estimate for the proposed facility. The plant design life shall be 20 years. Financing will be based on the Discounted Cash Flow method with the rate determined by the state of Montana. All products and by-products will be valued at current commercial market value. All portions of the operating cost estimate shall be readily identifiable.

3.13 Target Schedule

The contractor shall prepare a target bar chart schedule for the complete engineering, design, procurement, construction and start-up of the proposed facility. All major activities shall be identified and the estimated start and completion dates given for each activity. The activities shall include all applications, permits and approvals by all regulatory agencies and others having jurisdiction.

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4.0 DESIGN REQUIREMENTS

4.1 Environmental Regulations

A report titled "A Compendium of Federal, State and Local Emission Standards as Applicable to Glasgow, Montana" was prepared for Dravo Corporation by Morrison-Maierle, Inc., Helena, Montana. This report shall be used as a guide to the conceptual design contractor.

Generally speaking, federal regulations take precedence over state regulations and state regulations over local regulations, except the standard which affords the greatest protection to the environment is usually used.

In general, the following requirements must be met.

4.1.1 Waste Water - All effluent water is to be treated and returned to the process or discarded with solid waste in an environmentally acceptable manner.

4.1.2 Solids Disposal - Non-toxic solid wastes are returned to the mine. Toxic solids must be treated acceptably within the plant and disposed in approved sites.

4.1.3 Air Emissions - Air emissions from a coal gasification complex may fall into the categories of boiler plant emissions, process sulfur emissions, or fugitive emissions.

Boiler Emissions - A federal regulation exists for fossil fuel-fired steam generators having a heat input of over 250 million Btu per hour.

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4.0 DESIGN REQUIREMENTS (Cont'd.)

4.1 Environmental Regulations (Cont'd.)

This regulation is listed as Part 60, Chapter 1, Title 40, Code of Federal Regulations and gives the following limitations:

Component	Maximum Emission Pounds per Million Btu (HHV) Heat Input (solid fuel)
SO_2	1.2
NO_x	0.7 expressed as NO_2
Particulates	0.1

4.1.4 Process Sulfur Emissions - The EPA is drafting regulations and it is understood that the intent will be to require sulfur recovery equivalent to a Claus plant plus a tail gas treating plant. Sulfur recovery facilities shall be designed for a recovery of 99.8 percent of the sulfur in the fresh feed to the sulfur recovery units.

4.1.5 Fugitive Emissions - Are of two types; one is dust emissions from solids handling equipment; the other is miscellaneous gas emissions containing sulfur compounds. Scrubbing devices shall be included on all effluent gas streams containing particulates. The limit for sulfur compounds in miscellaneous gas streams is covered in the report by Morrison-Maierle, Inc.

4.2 Site Utilization

The site has been selected as the Glasgow Air Force Base which is located in northeastern Montana. A description of the characteristics of Glasgow AFB and vicinity is given in the Executive Summary of Siting

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4.0 DESIGN REQUIREMENTS (Cont'd.)

4.2 Site Utilization (Cont'd.)

Energy Facilities at Glasgow Air Force Base, Publication FEA/G-75/418, November, 1975. This report to the Federal Energy Administration was prepared by the Montana Energy and MHD Research and Development Institute, Inc., and edited by the FEA. The contractor developing the conceptual design shall work with the Montana Energy and MHD Research and Development Institute, Inc., in establishing the suitability of the Glasgow AFB for the construction of a coal-fueled gasification complex.

4.3 Spare Components

The contractor shall determine what equipment requires spares to insure continuous operation of the proposed facility.

4.4 Codes and Regulations

The facility shall be designed and shall conform to the requirements of all applicable state, federal, and local codes and regulations having jurisdiction over the installation.

4.5 Materials of Construction

The materials of construction shall be specified by the contractor and shall be those most suitable for the specified service.